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Advanced Utility Simulation Model Report of Sensitivity Testing Calibration, and Model Output Comparisons (Version 3.0)

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16. ABSTRACT
The report gives results of activities relating to the Advanced Utility Simulation Model (AUSM): sensitivity testing, comparison with a mature electric utility model, and calibration to historical emissions. The activities were aimed at demonstrating AUSM's validity over input variable ranges likely to be used for application runs. Univariate sensitivity tests demonstrated that AUSM runs and returns credible results for input ranges expected during model application and addressed issues raised by reviewers. AUSM was compared with Coal and Electric Utilities Model (CEUM) for EPA's 1987 interim base case to compare results and analyze reasons for differences between the output of the two models for 1990 through 2010. Experiments for 1980 through 1985 found ways to calibrate the model to historical emissions without resorting to scaling or ad hoc methods. All three activities resulted in increased confidence in AUSM for several reasons: AUSM worked well over a wide range of values; sensitivity tests and normal model inputs span such a wide range of possible values that the model will clearly work for any expectable set of inputs: outputs changed in directions and by magnitudes which were consistent with input changes and with analysts' understanding of electric utilities; and all outputs form a consistent set of results.

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Electric Utilities	Evaluation	Advanced Utility Simulation Model (AUSM)	14G
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Sensitivity			14B
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(VERSION 3.0)

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ABSTRACT

The Advanced Utility Simulation Model (AUSM) is one of four stationary source emission and control cost forecasting models developed by the Air and Energy Engineering Research Laboratory for the National Acid Precipitation Assessment Program. The AUSM projects air pollution emissions (sulfur dioxide, nitrogen oxides and particulate matter), cost of generation and pollution control, and electricity rates by consumer category by state and year.

This report documents the work preformed by the Science Applications International Corporation (SAIC) research team in evaluating the AUSM for release by the Environmental Protection Agency for general use. Three tests of AUSM performance were conducted by the SAIC research team.

- Single parameter sensitivity tests were submitted to demonstrate that AUSM runs and produces credible results for ranges of inputs expected during model application and to address issues raised by reviewers.

- AUSM was compared with ICF Inc. Coal and Electric Utilities Model (CEUM) for the Environmental Protection Agency (EPA) 1987 interim base case to compare results and analyze reasons for differences between the output of the two models for 1990 through 2010.

- Experiments were done for AUSM model years 1980 through 1985 to find ways of calibrating the model to historical emissions by implementing constraints that could be related to actual utility industry practices (i.e., without resorting to scaling factors or artificial constraints).

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

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ABBREVIATIONS

ITEM	DESCRIPTION
AFUDC	Allowance for funds used during construction
AUSM	Advanced Utilities Simulation Model
Billion	10^9
Btu	British thermal units (1 Btu = 1.055 kJ)
Ca/S	Calcium to sulfur mole ratio
CEUM	Coal and Electric Utilities Model
CF	Capacity factor
DISPATCH	The DISPATCH Module of the Advanced Utility Simulation Model
EEI	Edison Electric Institute
FGD	Flue Gas Desulfurization
FIPS	Federal Information Processing Standard
GW	Gigawatt
HHV	Higher heating value
ITC	Investment tax credit
kW	Kilowatts (1 kW = 1kJ/s)
kWh	Kilowatt hours (1 kWh = 3.6 MJ)
LDC	Load Duration Curve
LIMB	Lime Injection Multi-stage Burner
MMBtu	Million British thermal units (1 MMBtu = 1.055 x 10^6 kJ)
MPMS	Multi-period, Multi-state
MW	Megawatts
MWh	Megawatt hours (1 MWh = 3.6 GJ)
NAPAP	National Acid Precipitation Assessment Program
NCSM	National Coal Supply Model
NO_x	Nitrogen oxides
NSPS	New Source Performance Standard (1971)
NURF	National Utility Reference File
NURF80PC	Personal computer file of 1980 NURF Inventory data
PWh	Petawatt hours (1 PWh = 10^{12} kWh)
QUAD	Quadrillion (1 QUAD = 10^{15} Btu)
RNSPS	Revised New Source Performance Standard (1979)
SAIC	Science Applications International Corporation
SAS	SAS Institute, Inc., developer of a series of data analysis and management packages for the computer
SIP	State Implementation Plan
Trillion	10^{12}
SO_2	Sulfur dioxide
URGE	Universities Research Group on Energy
XMP	FORTRAN based linear programming package

1 INTRODUCTION

The Advanced Utility Simulation Model (AUSM) was developed to provide the modeling community and the National Acid Precipitation Assessment Program (NAPAP) with a publicly available, peer reviewed, nonproprietary model with accompanying data bases. This release of the model on magnetic tape (EPA-600/8-88-071-1) [12] and the series of technical documentation (EPA-600/8-88-071-a to -k) [references 1 through 12] lets users examine the analytical structure of the model and gives users the capability to forecast electric utility SO_2 emissions and emissions control costs.

The AUSM is the largest and most sophisticated electric utility industry model to be documented and released for general use. Because its use is unrestricted, the release of the AUSM model provides a major new tool for the modeling community.

SAIC implemented a test program to validate whether Version 3.0 of the AUSM was ready for release to the public domain. Three sets of testing and evaluation activities were undertaken:

- Univariate sensitivity tests were run for two reasons: to demonstrate that AUSM produces credible results for ranges of inputs expected during model application and to address issues raised by reviewers of the model.

- AUSM was compared with the ICF, Inc. Coal and Electric Utilities Model (CEUM) for the Environmental Protection Agency (EPA) 1987 interim base case. Results and reasons for differences between the output of the two models for 1990 through 2010 were analyzed.

- Experiments were conducted for the period 1980 to 1985 to find ways of calibrating the model to historical SO_2 emissions without resorting to scaling or ad hoc methods.

All three activities resulted in increased confidence in AUSM for several reasons. AUSM was shown to work well over a wide range of values. Sensitivity tests and normal model inputs span such a large range of possible values that the model will clearly work for any expectable set of inputs. Outputs changed in directions and by magnitudes which were consistent with input changes and with analysts' understanding of electric utilities. All outputs form a consistent set of results. Finally, the model was calibrated without any "forcing" or scaling of results.

1.1 Sensitivity Tests

There were three components of AUSM sensitivity validation. First, developmental testing was part of algorithm creation and coding/debugging. Second, the normal range of inputs used in running all 48 contiguous states proved that the model would accept substantial variation in economic, engineering, and inventory data. Third, sensitivity testing proved that the model would respond correctly to changes in remaining parameters likely to be involved in National Acid Precipitation Assessment Program (NAPAP) scenarios.

The EPA 1987 Interim Base case was the control case for all tests. Base case values were increased or decreased by constant fractions to generate sensitivity cases. Test comparisons were based on departures from base case results.

The following tests were created:

o Annual growth rates by state:		
	-- Low growth	50% below base case rates
	-- High growth	50% above base case rates
o Interstate transmission costs:		
	-- Low cost	80% below base case costs
	-- High cost	400% above base case costs
o FGD system capital costs:		
	-- Low cost	50% below base case costs
	-- High cost	100% above base case costs

These three tests were chosen because they built on other results and are important to NAPAP and/or organizations involved in reviewing AUSM. Changing growth rates for each state causes AUSM to simulate maximum use of existing capacity and addition of new capacity in the high case and to increase reserve margins for some years in the low case. High (low) interstate transmission costs would cause AUSM to simulate different dispatch patterns among states in a single region. Coal choices would change as a result of high (low) FGD system capital costs. These three tests examine the treatment of capacity planning, system dispatch, interstate transmission, and fuel choice within the AUSM.

1.2 CEUM Comparison

EPA has used the Coal and Electric Utilities Model (CEUM) for ten years as a policy evaluation/forecasting tool. Users have had ample exposure to interpretations of CEUM and have come to accept them as credible. Accordingly, a comparison of AUSM with CEUM was conceived as a good way of evaluating model forecasts.

Both models were run using scenario inputs representing the interim base case. In addition, some AUSM data were modified to match CEUM equivalents, although exact matching was not possible. Forecasts of SO_2 emissions, SO_2 emissions rates, generation, capacity, and fuel use for 1990 through 2010 were then compared. Differences in model outputs, which were generally not large, were analyzed and are discussed in Section 5 of this report.

1.3 Calibration Tests

AUSM runs always start in 1980. Model users, however, may set the total number of years in a simulation from 2 to 30 years. For the most part, utilities are assumed to be cost minimizers. In practice, utilities are also subjected to a number of other economic and regulatory forces. Thus, the forecast of historical SO_2 emissions can be different from actual emissions unless technical or other factors affecting utility operations are identified in advance by the model user. Several factors (i.e., turn-down ratios, availability limits and load curve shapes) have been added to constrain the cost minimization routine in AUSM to reasonable bounds. These factors were tested to determine if the constrained the cost minimization routine in AUSM to produced a good representation of annual utility SO_2 emissions. This was done by comparing the model's output to historical information.

It was decided that no scaling or other "forcing" constraints not directly related to utility operations would be used to cause forecasts for 1980 through 1985 to agree with actual 1980 through 1985 data. To do so would be to introduce doubt in the form of a question: Are AUSM forecasts due to simulation of utility operations or due to scaling factors buried in the model? Clearly, such doubt is to be avoided.

After extensive experimentation, the best forecast of historical SO_2 emissions was achieved by including dispatch constraints in the AUSM to mimic technical constraints on boiler operations. These constraints, known as turn-down ratios, set minimum boiler operation limits on units. Implemented as the least load to which a unit can be connected, these constraints cause each unit to be dispatched at a level ranging from the turn down ratio to its upper limit, which is imposed by availability considerations.

Technical constraints on dispatching units were imposed for two reasons. First, such constraints were not deemed to be intrusive because they model engineering constraints on actual generating units. For other kinds of units (e.g., turbines) there is a minimum load below which the unit cannot run based on historical data. Second, these constraints were instituted because AUSM models annual load demand and must have constraints applied to specific unit categories to account for hourly, daily or other short-term demands. In addition, different load curve shapes for summer and winter peaking systems were built into AUSM.

The result of adding these constraints to the dispatch module in the state level model was that forecast and actual 1980 through 1985 SO_2 emissions agreed closely. Forecasted emissions for each state were within 10 percent of actual values. In fact, most were within 5 percent. Additionally, the forecast distribution of capacity factors which had been unreasonably bimodal and/or strongly skewed when it was based solely on least cost minimization (i.e., without these added constraints), came into more reasonable agreement with the actual distribution.

1.4 General Conclusions

This testing demonstrated the following:

- AUSM will accept a wide range of input values. Values representing most scenarios will not cause the model to abort. Extreme values which do cause the model to abort were not established. But, such values clearly lie substantially above (below) values which will be used in applying AUSM.
- AUSM projections replicates history. Both SO_2 emissions and capacity factor distributions for 1980 through 1985 agree with history. This agreement provides support for 1990 through 2010 forecasts since it indicates that the model's constraints and data bases are adequate for projecting current industry operations.
- AUSM and CEUM generally agree. Disagreements are generally small with respect to all parameters; especially SO_2 emissions. However, there are distinct differences in the utilization of alternative sources of generation.

2 SENSITIVITY TO GROWTH RATES

Two runs of the AUSM, a high and a low electricity demand growth case, were conducted to assess the sensitivity of model output to user-defined growth rate assumptions. Default demand growth rates were adjusted for both cases; high case rates were increased by 50 percent and low case rates were decreased by 50 percent relative to a interim base case growth rate assumptions. These changes were made to the National Loop and the State Model input files for each time period and for each state.

2.1 Introduction

To ensure that the behavior of the AUSM comported with economic assumptions regarding growth in electricity demand, several acceptance criteria were established:

> Generating capacity for the high demand growth rate scenario should be higher than Base case generating capacity, but generating capacity for the low demand growth rate scenario should be lower than Base case generating capacity.
>
> Generation should be higher under high demand growth rate assumptions than under Base case demand growth rate assumptions, while generation should be lower given low demand growth rate assumptions than generation given Base case growth rate assumptions.
>
> Sulfur dioxide emissions for a high demand growth scenario should be higher than for the Base case, and lower than the Base case for the low growth demand rate scenario.

In addition to these criteria, the impact of changing demand growth rate assumptions on model results was also examined for fuel consumption.

2.2 Generating Capacity

Generating capacity levels determined by the AUSM are sensitive to electricity demand growth assumptions. As indicated in Figure 2.1, total generating capacity in the High Growth scenario exceeded the Base case, while total generating capacity in the Low Growth scenario was lower than the Base case. High Growth capacity exceeded Base case capacity by 6.93 percent to 22.02 percent or from 52.33 gigawatts (GW) to 193.40 GW between 1995 and 2009. Over this same period, total Low Growth capacity ranged from 2.96 percent lower to 12 percent (from 22.37 GW to 107.29 GW) lower than Base case capacity.

Figure 2.1 U.S. Generating Capacity
AUSM Sensitivity Analysis

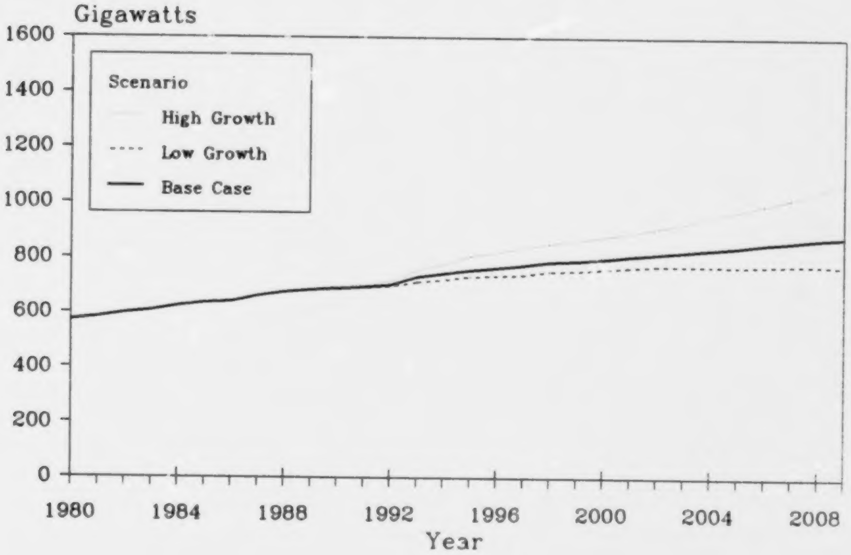


Figure 2.2 U.S. Generating Capacity
High Demand Growth Rate Scenario
Capacity by Unit Type

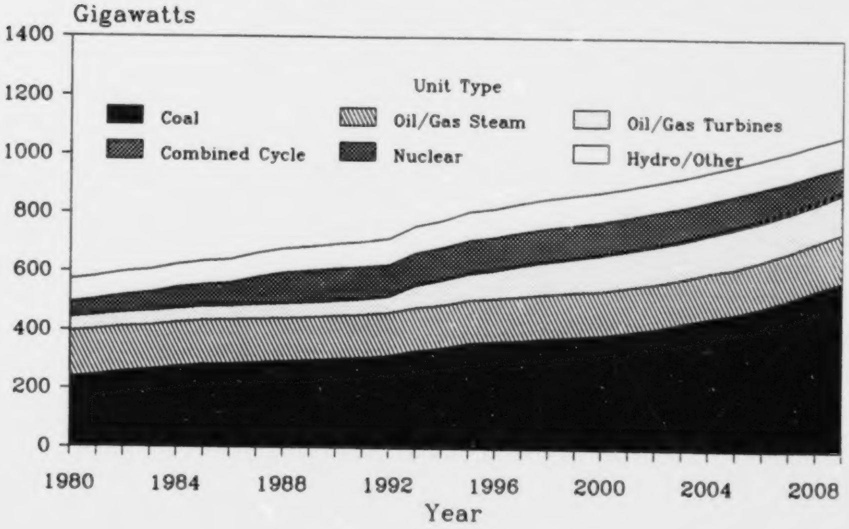


Figure 2.3 U.S. Generating Capacity

Low Demand Growth Rate Scenario

Capacity by Unit Type

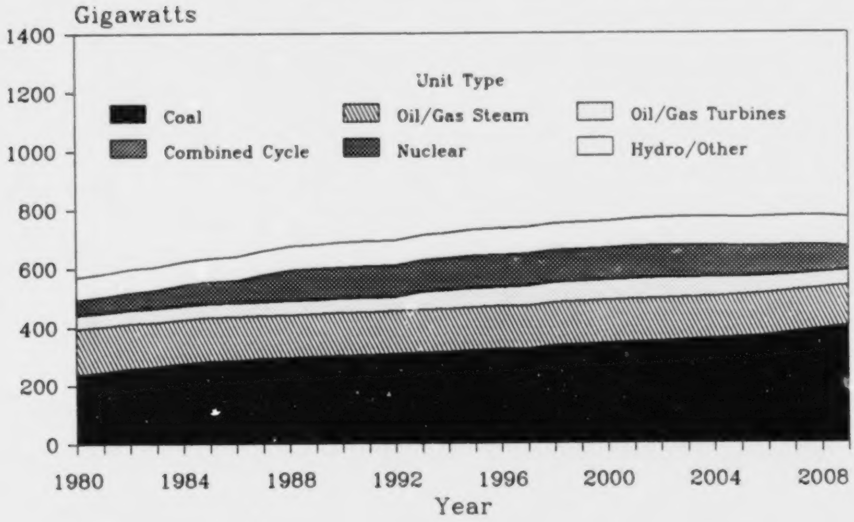
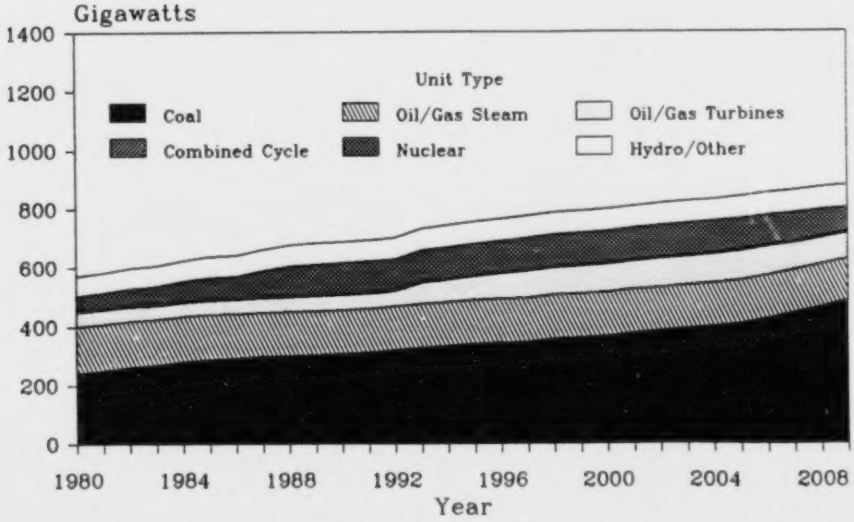


Figure 2.4 U.S. Generating Capacity

1987 Interim Base Case

Capacity by Unit Type



In addition to differences in generating capacity trends for these scenarios, the mixture of unit types comprising the capacity profiles of both scenarios also varied significantly compared to the Base case. As shown in Figures 2.2, 2.3, and 2.4, the variation in the capacity profile mixture for both the High Growth case and the Low Growth case changed considerably relative to the Base case after 1995.[1] These figures also indicate that capacity from coal units complying with Revised New Source Pollution Standards (RNSPS), oil turbine units, and gas turbine units in the High Growth case displaced capacity from coal State Implementation Plan (SIP) plants, coal units complying with the New Source Pollution Standards (NSPS), nuclear units, and hydroelectric/other units in the Low Growth rate case. Capacity mixes in all of the scenarios reflect an increasing dependence on coal-fired units to meet demand, but the High Growth case clearly has the highest proportion of coal-fired units in its capacity profile.

2.3 Generation

A positive correlation between demand growth rate assumptions and the level of generation, was also investigated. Once again, the sensitivity results corroborated assumptions regarding how the AUSM should respond to growth rate changes -- total generation for the High Growth scenario exceeded the Base case and total generation for the Low Growth scenario was lower than the base case (see Figure 2.5). High Growth generation was 11.58 percent to 27.67 percent (333.20 GW to 1036.24 GW) higher than Base case generation from 1995 to 2009. Low case generation, though, was 5.92 percent to 17.32 percent (169.48 GW to 648.76 GW) lower than Base case levels over this period.

The mix of units making up each scenario's national generation profile varied according to assumed growth rates. As a fraction of total generation, the AUSM High Growth case used more coal-fired capacity (particularly from RNSPS units) and more oil/gas turbine capacity than was used under the Base case. By comparison, the Low Growth scenario resulted in proportionately greater use of coal-fired SIP and NSPS units, nuclear units, and hydroelectric units than in either the High Growth case or the Base case. These trends are presented in Figures 2.6, 2.7, and 2.8. Proportionately greater use of SIP units is expected with low demand growth rates because existing units are dispatched more since there is not enough demand to justify constructing new units.

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[1] The variation in the capacity mixes of these scenarios as of 1995 is significant because this is the first year that model-determined capacity additions are permitted to come on-line.

Figure 2.5 Total U.S. Generation

AUSM Sensitivity Analysis

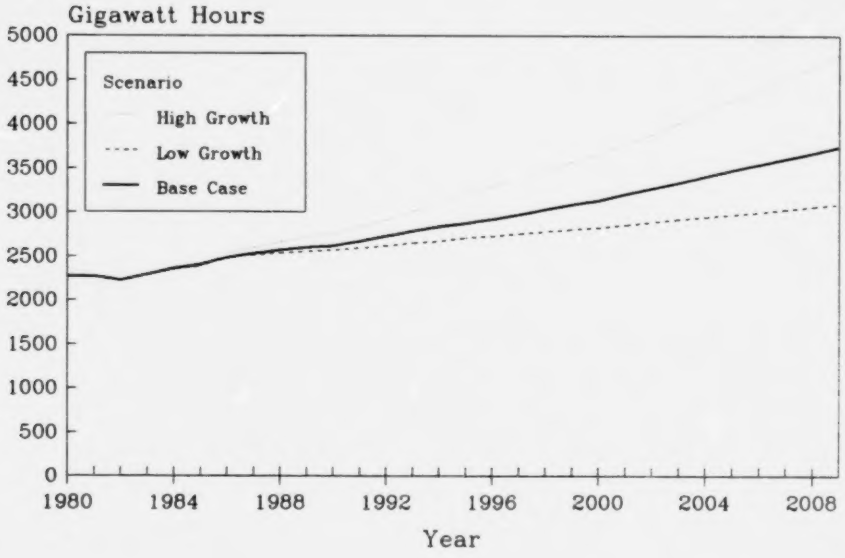


Figure 2.6 Total U.S. Generation

High Growth Rate Scenario

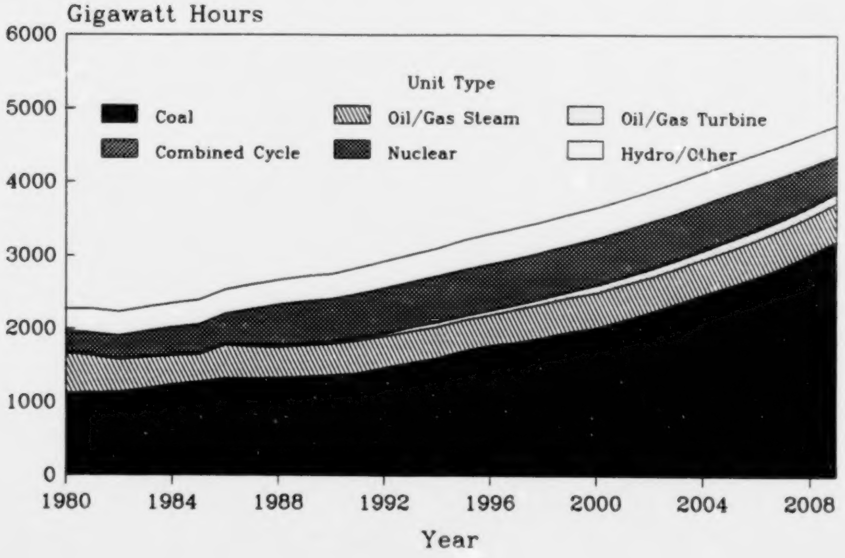


Figure 2.7 Total U.S. Generation

Low Growth Rate Scenario

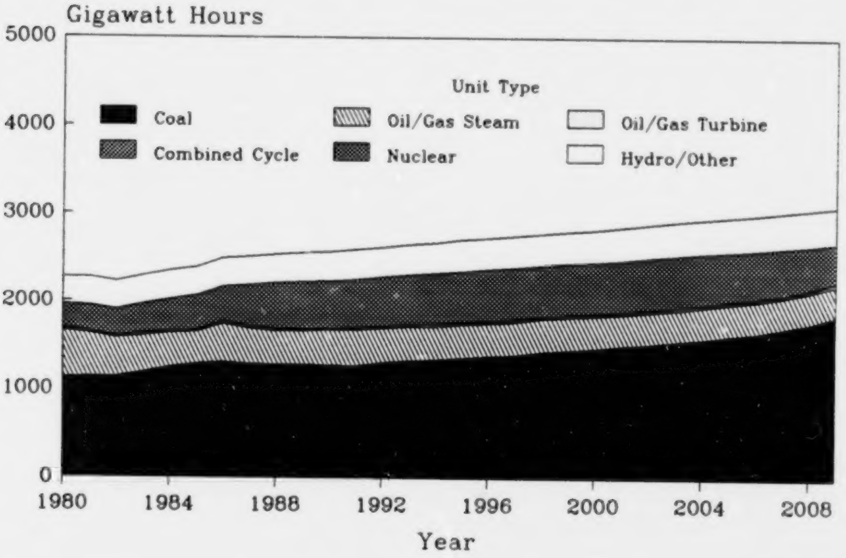
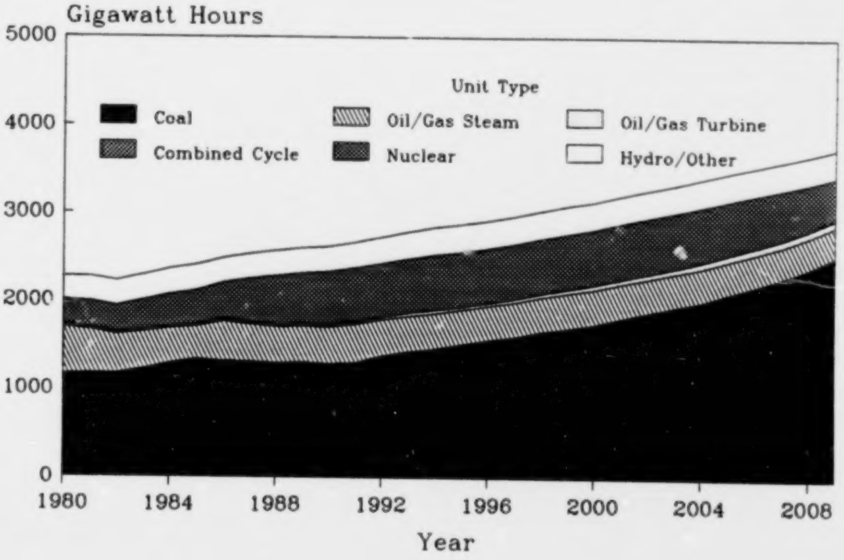


Figure 2.8 Total U.S. Generation

1987 Interim Base Case



2.4 Sulfur Dioxide Emissions

SO_2 emission forecasts are highly dependent upon capacity and generation profiles. In turn, these profiles are linked to growth rate assumptions. The sensitivity of changes in demand growth rates to sulfur dioxide emissions was considered in the following two ways. First, differences in total SO_2 emissions for the High Growth, the Low Growth, and the Base case scenarios were examined. A second analysis was undertaken in which SO_2 emission levels for each scenario were considered simultaneously for each type of coal unit (SIP, NSPS, and RNSPS). The findings are discussed below.

Acceptance criteria for the AUSM SO_2 emissions sensitivity forecasts were successfully met: the national emissions forecast for the High Growth scenario exceeded the Base case, and the U.S. SO_2 emissions forecast for the Low Growth scenario was lower than the Base case. These results are graphically presented in Figure 2.9. High Growth SO_2 emissions were 9 percent to 15 percent greater than the Base case levels from 1995 to 2009. Low Growth SO_2 emissions, on the other hand, were 5 percent to 13 percent lower than Base case SO_2 emissions over this period.

In absolute terms, there was little cross scenario variation in the NSPS, coal-fired SO_2 emissions forecasts. Only a half-million tons separates the High Growth case and the Low Growth case. Between 1995 and 2009, High Growth NSPS SO_2 emissions were 9 to 12 percent higher than the Base case forecast. Conversely, Low Growth NSPS SO_2 emissions were 6 to 16 percent lower than the Base case forecast. In each scenario, NSPS SO_2 emissions only accounted for about 10 percent of the total SO_2 emissions forecast. All of these trends are depicted in Figure 2.10.

High Growth and Low Growth scenario RNSPS coal SO_2 emissions differed substantially from the Base case forecast. As expected, SO_2 emissions from the High Growth scenario were much higher than levels reported in both the Base case and the Low Growth case summary reports. In fact, High Growth SO_2 emissions were about 49 percent higher than the Base case in 2009, whereas Low Growth SO_2 emissions were about 47 percent lower than the Base case in 2009 (see Figure 2.11). Large differences in these respective forecasts are based on two related factors. The AUSM had to construct more RNSPS units (the only type of coal unit the model is permitted to build after 1995) under the High Growth scenario in order to meet increasing load requirements. As a result, SO_2 emissions under these growth assumptions increased because generation and capacity increased. Yet, in the Low Growth scenario load demands were so low there was no consequent increase in capacity or generation. Sulfur dioxide emissions for this scenario, therefore, decreased.

The sensitivity of SIP emission trends resulting from changes to demand growth rates is important because coal-fired SIP units accounted for at least 70 percent of SO_2 emissions projected by the AUSM by 2009, in each scenario. Sulfur dioxide emissions from coal-fired SIP units were sensitive to changes in demand

Figure 2.9 U.S. S02 Emissions
AUSM Sensitivity Analysis

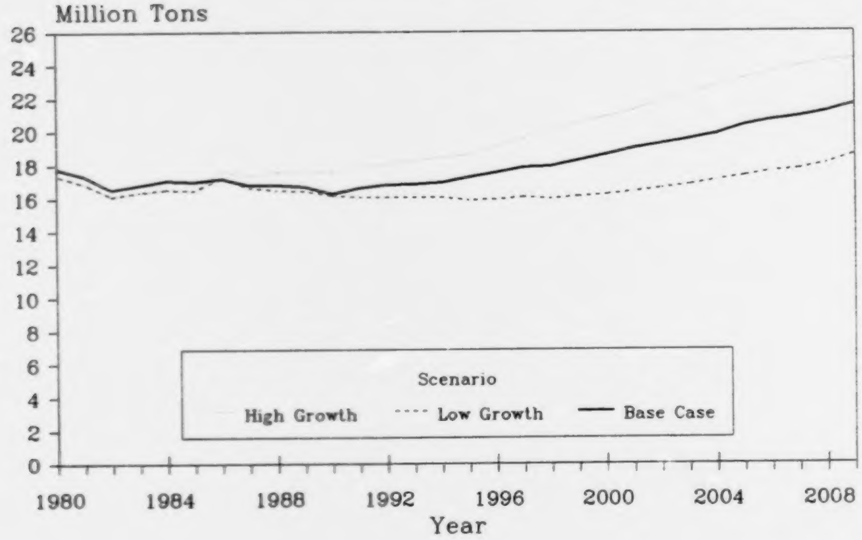


Figure 2.10 Total NSPS S02 Emissions
AUSM Sensitivity Analysis

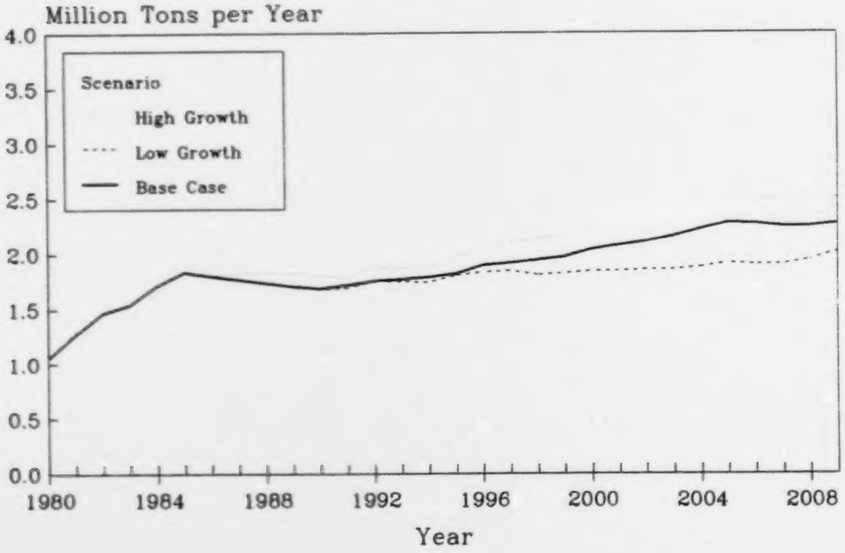


Figure 2.11 Total RNSPS S02 Emissions
AUSM Sensitivity Analysis

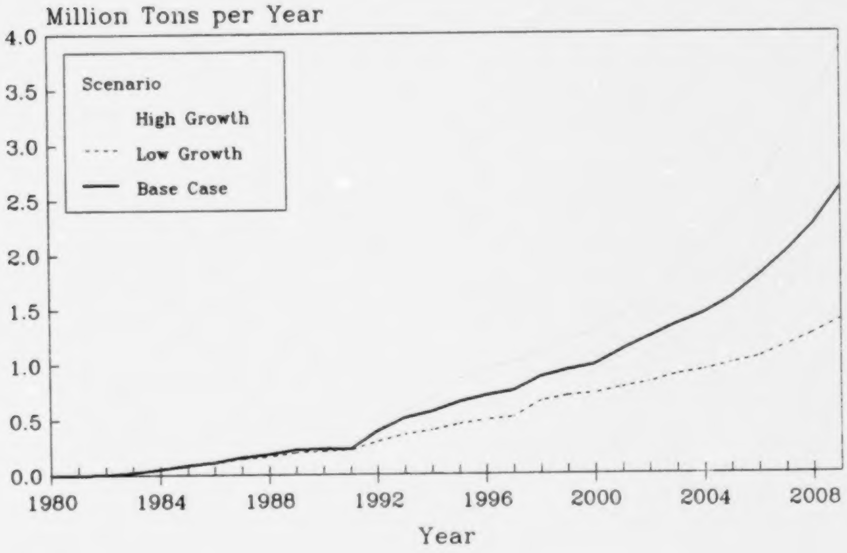
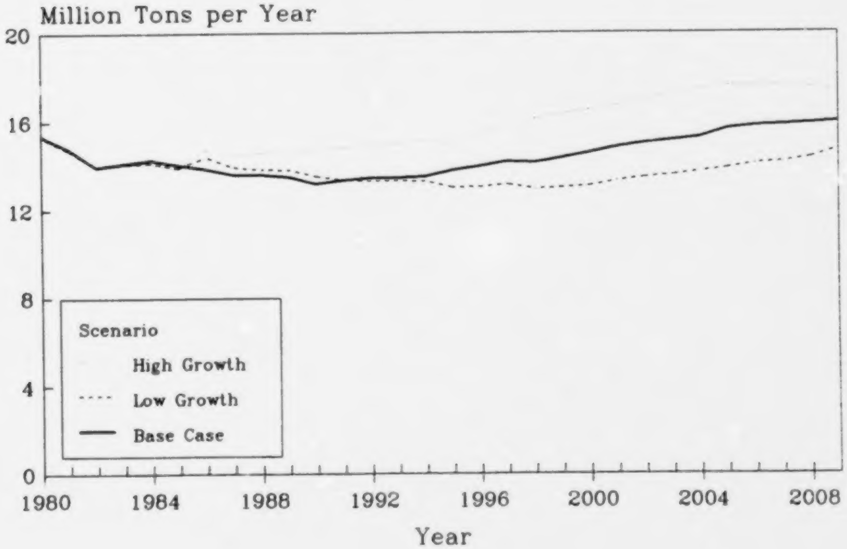


Figure 2.12 Total SIP S02 Emissions
AUSM Sensitivity Analysis



growth rates. From 1995 to 2009 High Growth SIP SO_2 emissions were about 8 to 14 percent greater than Base case SIP SO_2 emissions, while Low case SIP SO_2 emissions were about 5 to 11 percent lower than the Base case for this period (see Figure 2.12).

Total, coal-fired, SIP SO_2 emissions increased under the High Growth case relative to the Base case because these units had to be dispatched more to meet future load demands. The converse was true of the Low case.

2.5 Fuel Consumption

In each sensitivity the minimum cost mix of fuels selected by utilities was influenced by varying the demand growth rates. Fuel consumption mixes among the scenarios were distributed differently even though the total fraction of coal consumption for each scenario was about the same (roughly 80 percent). Variation among these fuel consumption profiles is highlighted in Figures 2.13, 2.14, and 2.15.

Significant differences in fuel consumption patterns exist between the High Growth case and the Base case. For example, the consumption of low sulfur coal (standard of less than 1.2 pounds per MMBtu) was 61 percent higher for the High Growth case compared to the Base case in 2009. More low sulfur coal was used in the High case because of the large number of RNSPS units built under the High case to satisfy load demands. Coal units complying RNSPS must burn extremely low sulfur coal. High Growth and Base case fuel consumption patterns for other coals were more similar (though somewhat higher in the High Growth case). These patterns are shown in Figures 2.17 through 2.22.

High Growth fuel consumption of oil and gas was 48 percent and 59 percent greater than Base case consumption of these respective fuels by 2009. Again, oil and gas consumption were much higher in the High Growth case because more of these units were constructed to satisfy load increased load demands.

Unlike the High Growth rate case, changing demand growth rate assumptions did not drastically affect the Low Growth scenario fuel consumption pattern. Base case and Low Growth case fuel consumption trends for oil, gas and medium-to-high sulfur coal (standard of 2.0 to 4.0 pounds per MMBtu) are all very similar (see Figures 2.20, 2.21, and 2.18). By 2009, Low Growth consumption of low-to-medium sulfur coal (standard of 1.2 to 2.0 pounds per MMBtu) was, however, 42 percent lower than Base case consumption.

2.6 Conclusion

In summary, sensitivity analyses showed that the AUSM produces results consistent with economic assumptions about the growth in electricity demand. In other words, model results were sensitive to user-defined demand growth rate parameters. For example, while increasing demand growth rates resulted in the model building more units, generating more energy, emitting more sulfur dioxide and using relatively cleaner coal; lowering demand growth rates resulted in the model building fewer units, generating less energy, emitting less sulfur dioxide, and using relatively dirtier coals. In all the scenarios -- the capacity profile was skewed to coal as the simulations progressed. Overall, the AUSM appears to have behaved in accordance with economic assumptions.

Figure 2.13 U.S. Fuel Consumption

High Demand Growth Rate Scenario

Fuel Component Analysis

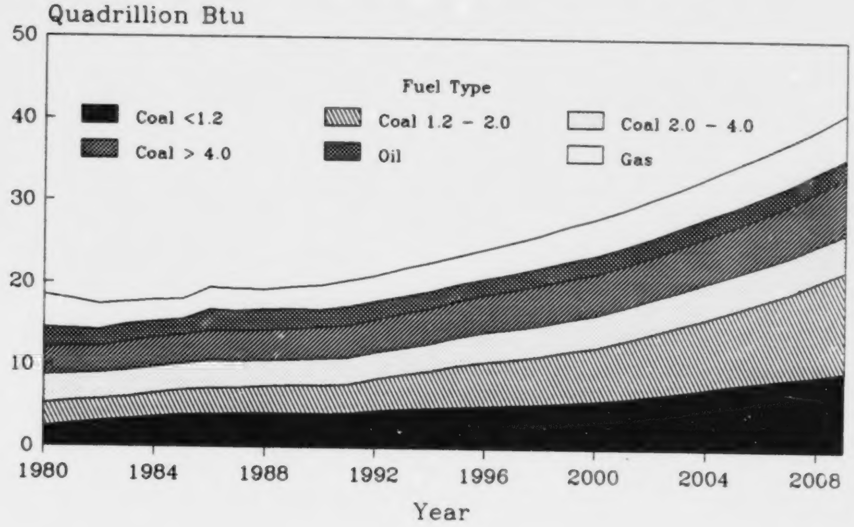


Figure 2.14 U.S. Fuel Consumption

Low Demand Growth Rate Scenario

Fuel Component Analysis

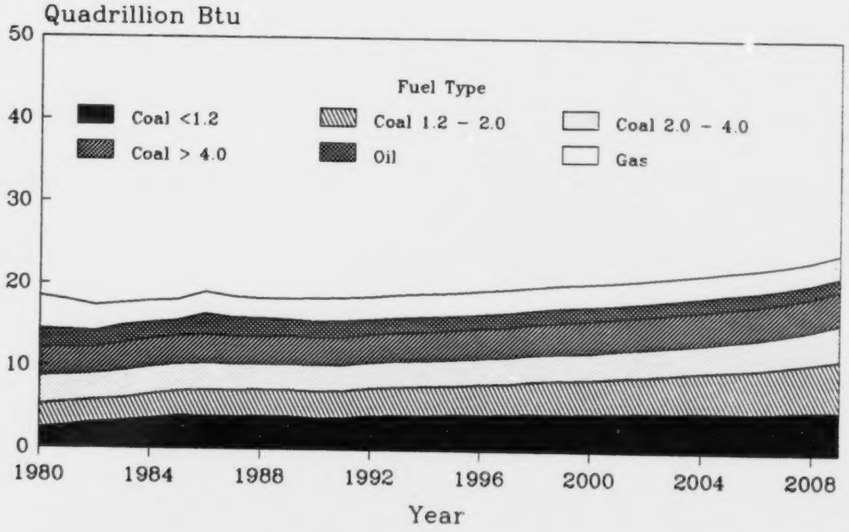


Figure 2.15 Total U.S. Fuel Consumption

1987 Interim Base Case

Fuel Component Analysis

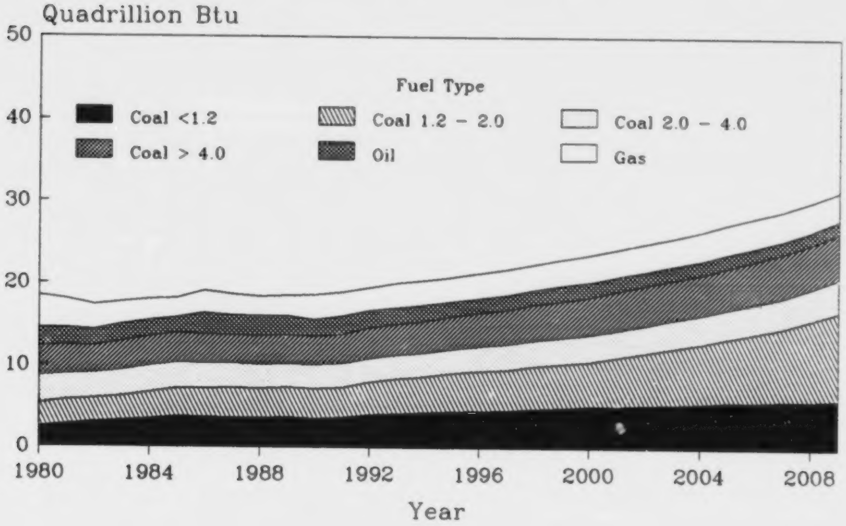


Figure 2.16 U.S. Fuel Consumption

AUSM Sensitivity Analysis

Fuel Type: Coal 0.0 - 1.2 pounds/MMBtu

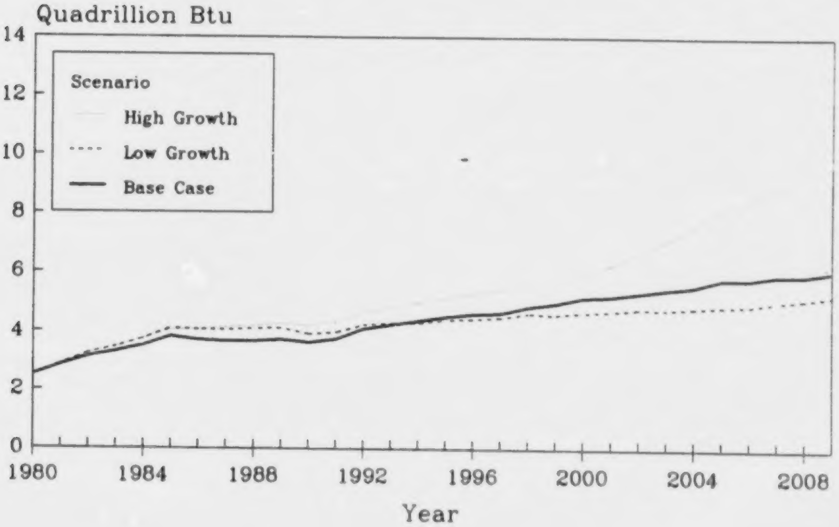


Figure 2.17 U.S. Fuel Consumption

AUSM Sensitivity Analysis

Fuel Type: Coal 1.2 – 2.0 lb./MMBtu

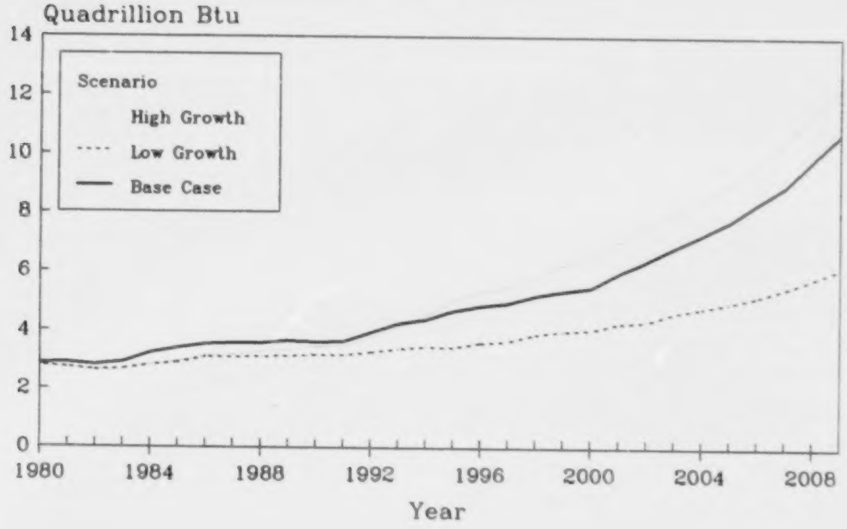


Figure 2.18 U.S. Fuel Consumption

AUSM Sensitivity Analysis

Fuel Type: Coal 2.0 – 4.0 lb./MMBtu

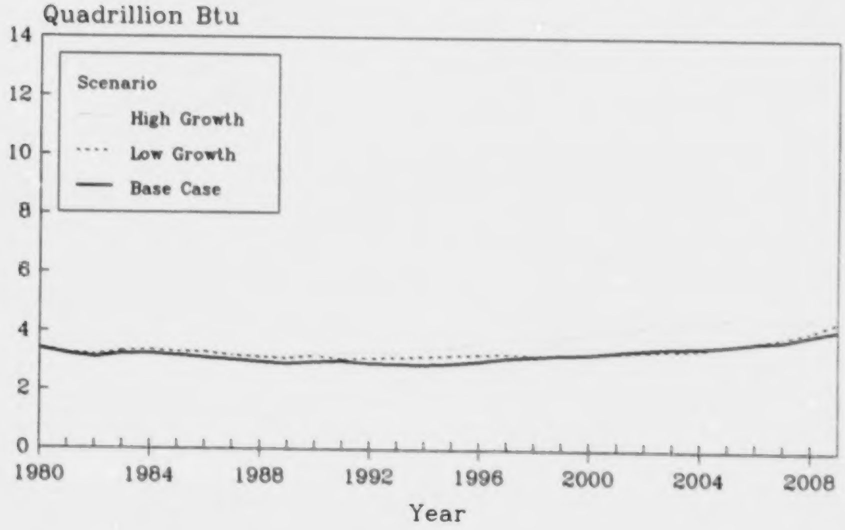


Figure 2.19 U.S. Fuel Consumption

AUSM Sensitivity Analysis

Fuel Type: Coal > 4.0 pounds/MMBtu

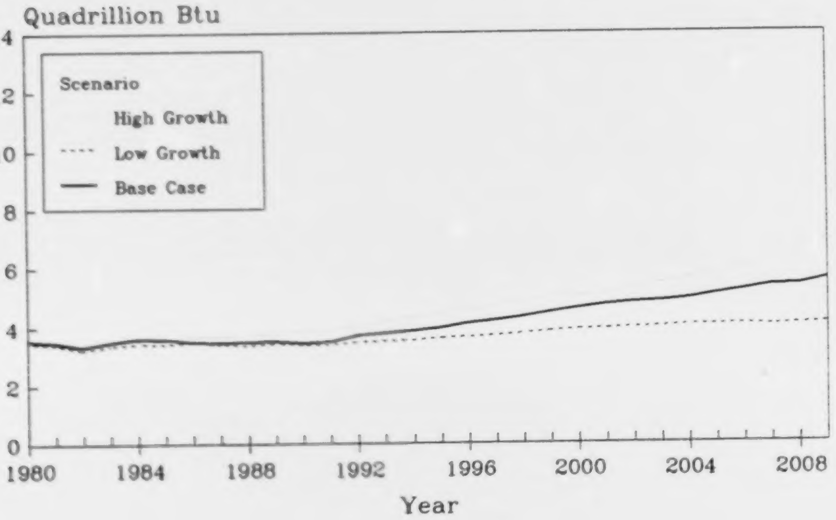


Figure 2.20 U.S. Fuel Consumption

AUSM Sensitivity Analysis

Distillate and Residual Oil Consumption

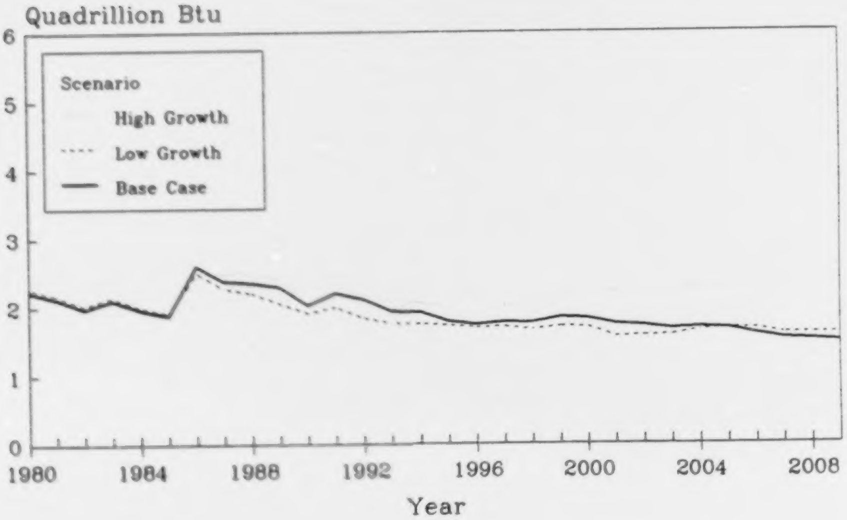
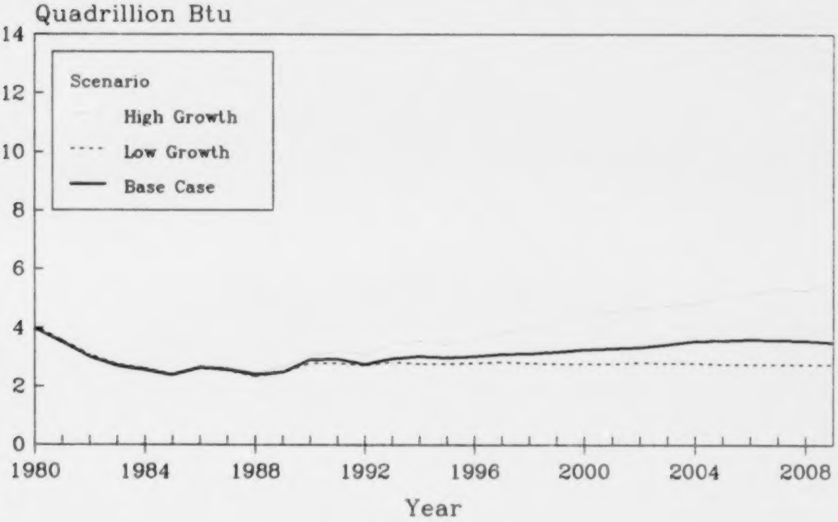


Figure 2.21 U.S. Fuel Consumption
AUSM Sensitivity Analysis
Natural Gas Consumption



3 FGD COST CHANGE ANALYSIS

Two AUSM Fluidized Gas Desulfurization (FGD) cost sensitivity tests were developed: a High case in which capital costs associated with installing FGD devices were increased 100 percent above the Base case and a Low case in which these costs were decreased by 50 percent from the Base case.

3.1 Introduction

Changes in FGD cost assumptions are expected to influence utility selection of coal types and scrubber additions. A negative relationship is expected between utility purchases and the cost of scrubbing units. High sulfur coal should be replaced by lower sulfur coal used as capital costs of scrubbers increase. The following categories of AUSM results for the FGD cost scenarios will be analyzed for responsiveness to the cost variation:

- Sulfur dioxide emissions
- Electricity generation
- Coal consumption by sulfur content
- Regional coal prices.

3.2 Sulfur Dioxide Emissions

SO_2 emission forecasts in the two studies produced results in line with expect utility behavior patterns. The results of the three scenarios showed a negative relationship between scrubber costs and SO_2 emissions. Lower capital costs of scrubbing units induced the model to select higher sulfur fuels and more scrubbing units. In turn, higher scrubber costs result in lower sulfur content fuel use.

3.2.1 Coal Units

Decreasing FGD capital costs in the Low case resulted in raising sulfur dioxide emissions by less than 2 percent above the Base case levels. (See Figure 3.1.) This increase in total SO_2 emissions also raised SO_2 emission rates after 1995 when capacity with new scrubbing units began coming on line. The addition of scrubbers in the Low FGD cost scenario enabled utilities to purchase less expensive, higher sulfur coal.

Figure 3.1 Coal Unit S02 Emissions
FGD Cost Scenario Comparison
Region 4: N. & S. Carolina & Virginia

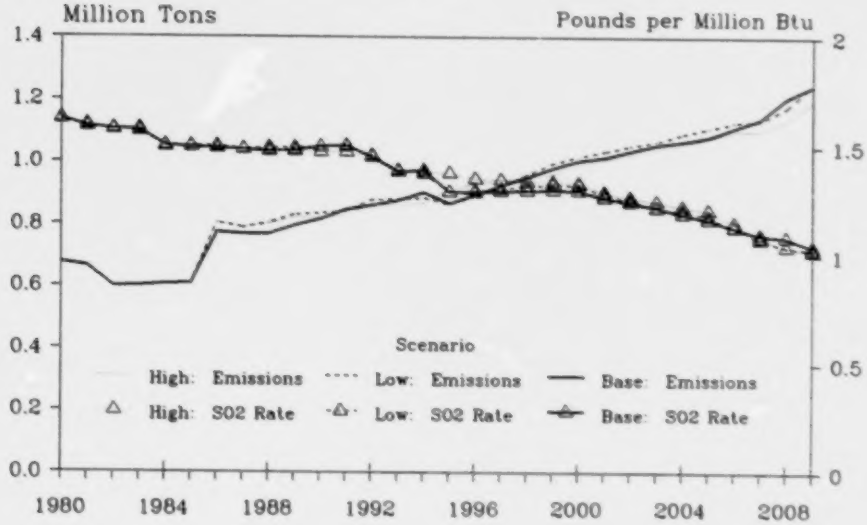
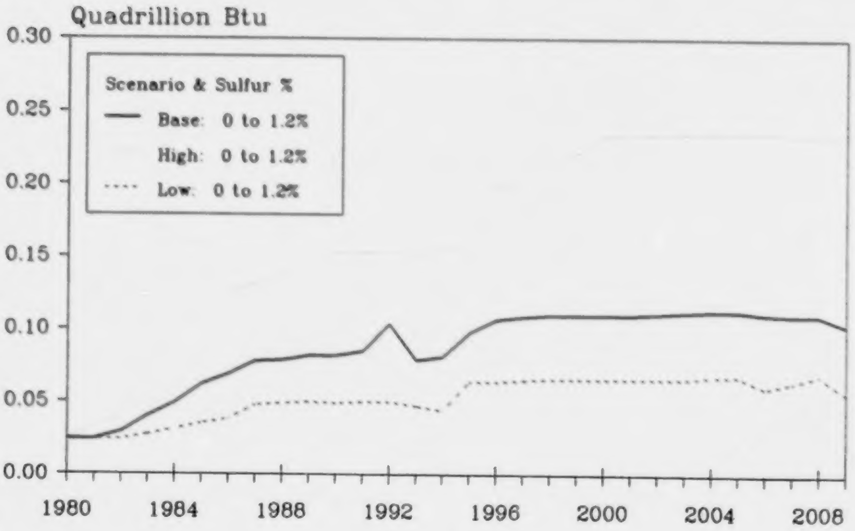


Figure 3.2 Coal Consumption
FGD Cost Scenario Comparison
Region 4: N. & S. Carolina & Virginia



By 2009 about 1.5 quads of coal below 2 pounds per MMBtu sulfur content was replaced in the High case with lower cost coal containing sulfur between 2 and 4 pounds per MMBtu. SO_2 emission rates for coal-fired units in the High case increased above the Base case levels between 1995 and 2007 as a result of increased use of high sulfur coal (sulfur content above 2 pounds per MMBtu). The higher scrubbing unit costs caused utilities to substitute low sulfur coal for the installation of scrubbing units.

3.2.2 Oil and Gas Units

Utility SO_2 emission rates from oil and gas plants fluctuated in the Low case across the forecast period. Prior to 1994, SO_2 rates for the Low case were below the Base case; Low case SO_2 emission rates were higher than the Base cased after 2000 (Figure 3.5). SO_2 emission rates in the High case are greater than the Base case results from 1995 through 2007, while total SO_2 emission was about 30 percent lower by 2009.

In contrast to the Low case, the High case produced lower total SO_2 emission and higher emission rates. SO_2 emission rates for oil and gas-fired units declined at a faster rate in the High case compared to the Base case prior to 2002. After 2002, Low case emission rates leveled off while the Base case rates continued to decrease. In sum, the results reveal that total SO_2 emission moved in the expected, inverse direction of FGD scrubber cost changes and SO_2 emission rate changes followed the direction of the FGD costs.

3.3 Coal Consumption by Sulfur Content

As expected, relatively higher sulfur coals were selected under the Low cost case because of the availability of inexpensive scrubbing options (see Figures 3.2 and 3.4). Low case consumption of low sulfur coal (less than 1.2 pounds per MMBtu) was about 40 percent less than the Base case levels (Figure 3.2). Low sulfur coal consumption in the Base case ranged from 0.03 quads in 1980 to about 0.1 quads by 2009 compared to about 0.05 quads by 2009 in the Low case.

Low case medium sulfur coal (1.2 to 2.0 pounds per MMBtu) consumption dropped between 1992 and 1997 and then returned to its pre-1992 level of 0.09 quads through 2009 (Figure 3.3). High sulfur coal consumption in the Low case rose from 0.2 quads in 1991 to almost 1.5 quads by 2009. Base case levels over this period were unchanged (Figure 3.4).

Capital costs in the High case were increased by a factor of 2 over the Base which resulted in lower SO_2 emission and SO_2 emission rates. (See Figure 3.1.) For much of the simulation the AUSM selected low sulfur coal rather than adding scrubbers in the High case. After 2005, consumption of high sulfur coal (sulfur content above 2 pounds per MMBtu) returned to base case levels, presumably as coal prices and scrubber costs reached parity.

Figure 3.3 Coal Consumption

FGD Cost Scenario Comparison
Region 4: N. & S. Carolina & Virginia

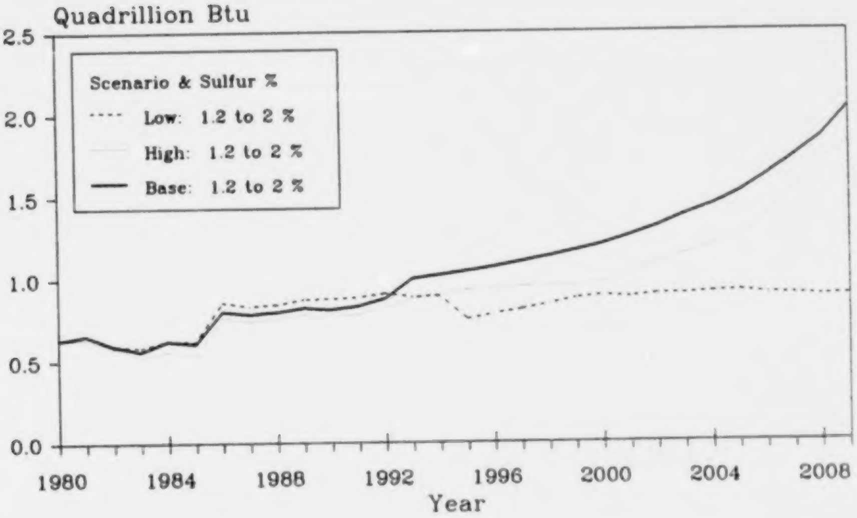


Figure 3.4 Coal Consumption

FGD Cost Scenario Comparison
Region 4: N. & S. Carolina & Virginia

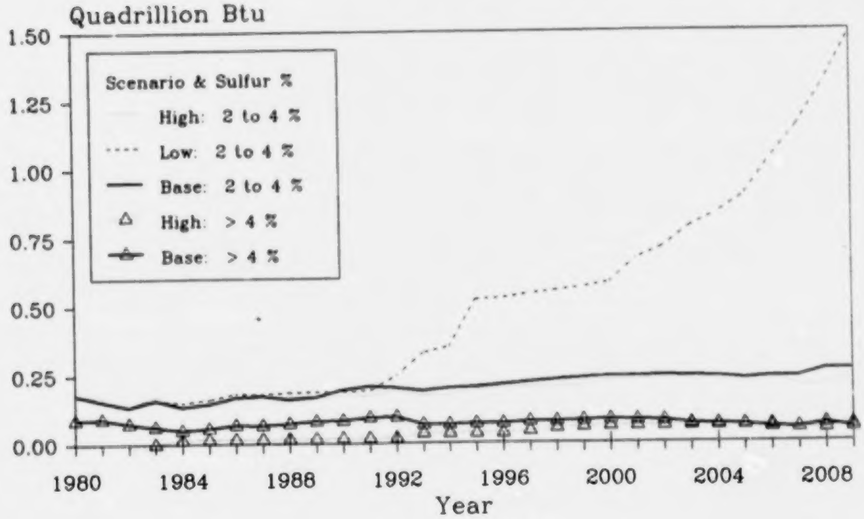


Figure 3.5 Oil & Gas Unit SO2 Emissions

FGD Cost Scenario Comparison

Region 4: N. & S. Carolina & Virginia

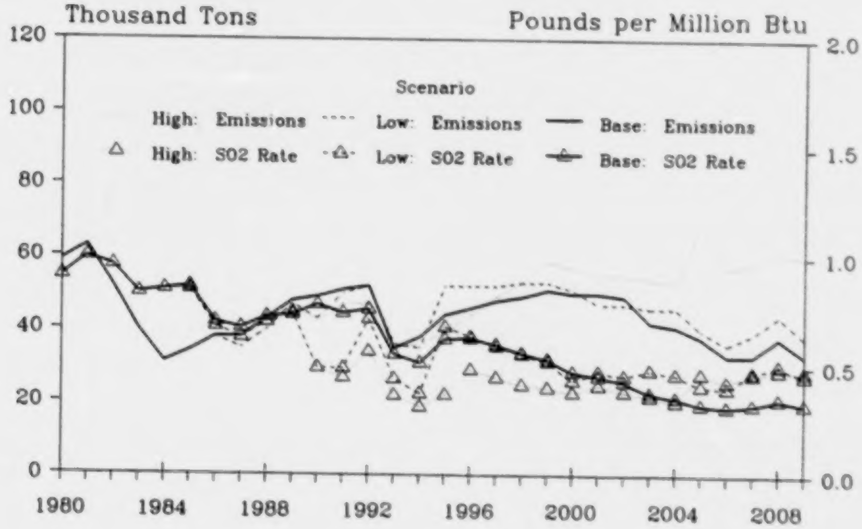
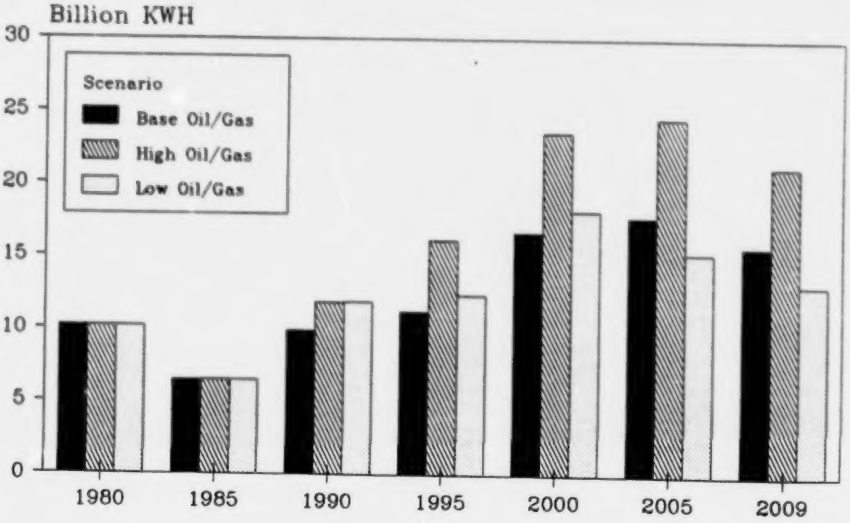


Figure 3.6 Oil & Gas Generation

FGD Cost Scenario Comparison

Region 4: N. & S. Carolina & Virginia



Low sulfur coal consumption in the High case doubles the Base case quantities by 1996 and increases by about 20 percent more by 2009 (Figure 3.2). For coal with sulfur content above 4.0 pounds per MMBtu consumption rose from zero in 1983 to about 0.06 quads by 2005 to be greater than the Base case estimates for that year (Figure 3.4). Coals with sulfur content between 1.2 and 4.0 pounds per MMBtu were consumed at a lower level than the Base case. Given the higher FGD capital costs plants would need to burn low sulfur coal to lower emission rates and the units with new scrubbers are able to burn the cheaper high sulfur coal.

3.4 Generation

The increased utility coal use lowered demand for oil and gas generation (Figure 3.6). Lower FGD costs further affected oil & gas emission levels by lowering costs of desulfurizing oil emissions. AUSM added scrubbers early in the forecast which lowered SO_2 emission rates quickly and once the units were installed emission rates leveled off. Higher emission levels for oil and gas fired units for the Low case after 1993 were the result of utilities shifting consumption to high sulfur oil (Figure 3.7).

Electricity generation by coal units is relatively equal over all years between the three cases, with the Low case generation slightly higher than the Base and High cases (Figure 3.8). For oil and gas fired units High case generation is between 4 and 11 billion kWh higher than the Base and Low cases after 1995 (Figure 3.6). Utilities are replacing a small amount of coal generation with oil and gas generation as coal generating costs increase in the High case compared to the other 2 cases.

3.5 Regional Coal Prices

Coal prices for Region 4 show North Carolina above the Base for both the High and Low cases (Table 3.1). For South Carolina and Virginia the price trends for the High and Low cases are inverse initial expectations. Low case prices are above the Base and High case prices are below the Base for both South Carolina and Virginia. This is the result of coal type switching between scenarios. The price differences are between 3 and 18 cents of the Base case for most coal types, which is not a significant variation given the magnitude of the scrubber cost changes. In South Carolina the price of low quality coal in the High case is 61 cents below the Base case, which is the result of the huge increase in lower cost high sulfur coal consumption.

The coal price variation across the scenarios are the result of the model switching consumption to low sulfur coal in the High case and to high sulfur coal in the Low case. A portion of the price variation in the High and Low cases was offset by the decline in medium sulfur coal consumption.

3.6 Conclusion

Changing the capital cost of scrubbing units resulted in the model replacing high sulfur coal types with low sulfur coal when FGD costs increased and not installing additional units beyond those required by regulation. The converse occurred as capital costs were lowered below the Base case; more scrubbers were installed and higher sulfur coal consumption was increased.

State	Coal Quality	Price Difference from Base Case	
	Percent Sulfur	Low Case	High Case
North Carolina	0 to 1.2	0.04	0.04
	1.2 to 2.0	0.08	0.14
	2.0 to 4.0	0.07	0.15
	above 4.0	0.03	0.14
South Carolina	0 to 1.2	0.03	-0.04
	1.2 to 2.0	0.08	-0.06
	2.0 to 4.0	0.07	-0.06
	above 4.0	0.03	-0.61
Virginia	0 to 1.2	0.05	0.01
	1.2 to 2.0	0.07	-0.00
	2.0 to 4.0	0.04	-0.02
	above 4.0	-0.18	-0.10

Table 3.1 FGD State Coal Price Comparison

Figure 3.7 Oil & Gas Consumption
FGD Cost Scenario Comparison
Region 4: N. & S. Carolina & Virginia

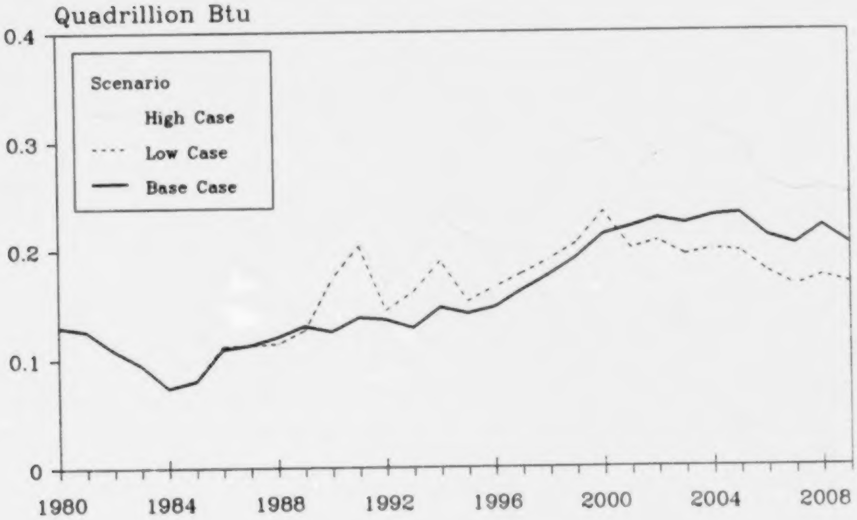
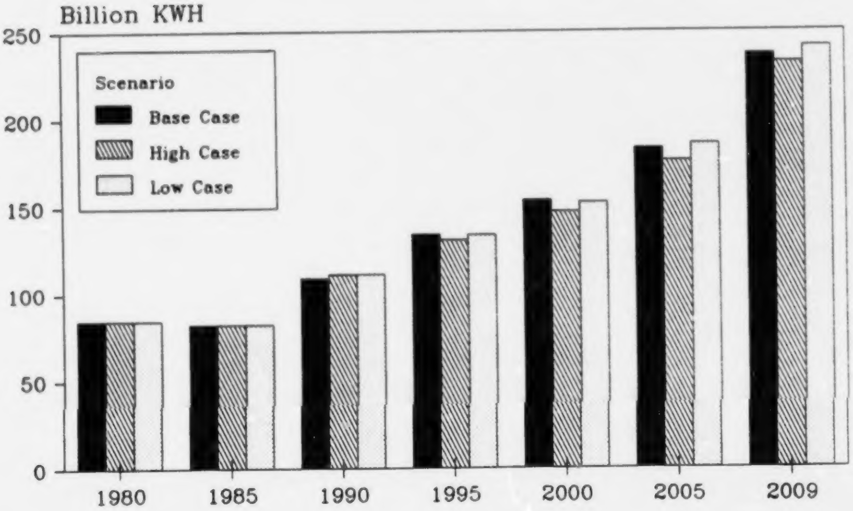


Figure 3.8 Coal Generation
FGD Cost Scenario Comparison
Region 4: N. & S. Carolina & Virginia



4 TRANSFER COST SENSITIVITY ANALYSIS

The sensitivity of the AUSM to interregional transfer level assumptions was modeled by manipulating the line rental fees in the National Loop of the AUSM. A High transfer cost scenario (High case) and a Low transfer cost scenario (Low case) were implemented to examine model sensitivity to transfer inputs. Line rental fees were decreased by 80 percent in the Low transfer cost scenario; line rental fees in the High case were increased 500 percent.

4.1 Introduction

Results for the AUSM transfer cost sensitivity scenarios are examined for the following categories:

- Generation by coal units,
- Utility generating capacity,
- Sulfur dioxide emissions.

Using Base case results as a reference, changes in power transfer costs implemented for this sensitivity study produced the anticipated patterns in electricity generation, plant capacity, primary fuel use and sulfur dioxide emission levels. For example, power transfers drop to zero after 2000 when transfer costs were increased by a factor of 5. Conversely, power transfers were on average 30 percent greater when transfer costs were decreased 80 percent.

4.2 Generation by Coal Units

High case coal generation drops below Base case generation for the model years following 2000 when power transfers decline to zero (see Figures 4.1 and 4.2). Mixed transfer results are evidenced for the Low case: coal generation is higher than Base case levels when power transfers are greater. Power transfers fall below Base case levels when Low case generation is less than Base case generation levels (see Figure 4.2). Low case power transfers on average equal 11 percent of total regional generation compared to 7 percent in the Base case and total generation differs by less than 0.1 percent. In comparison High case power transfers are about 3 percent of total generation.

Power transfers between states are insensitive to line fee variations. For example, the model required a 500 percent decrease to cause transfers to double by 2005 in the Low case. On the other hand, transfers in the High case changed at a more rapid pace. The results indicate that for the most part power transfers fill excess demand requirements, which is the intention. Changing line rental

Figure 4.1 Coal Generation
Transfer Cost Analysis
Region 4: N. & S. Carolina & Virginia

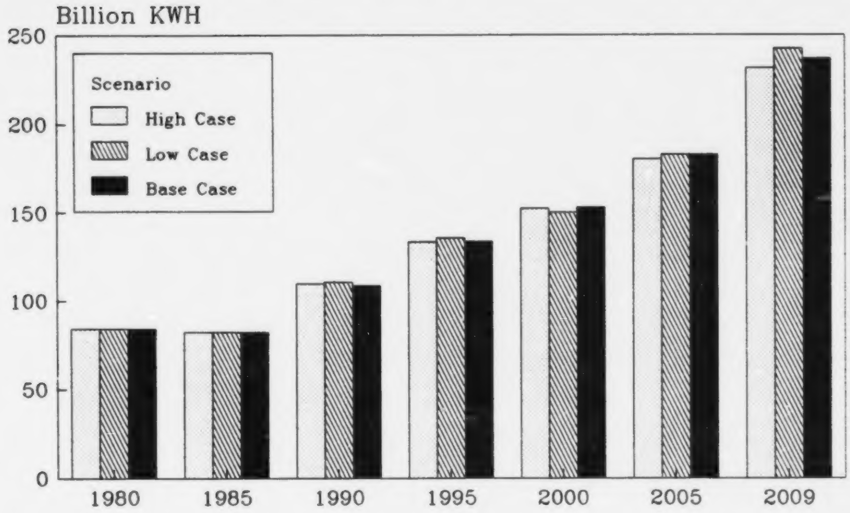
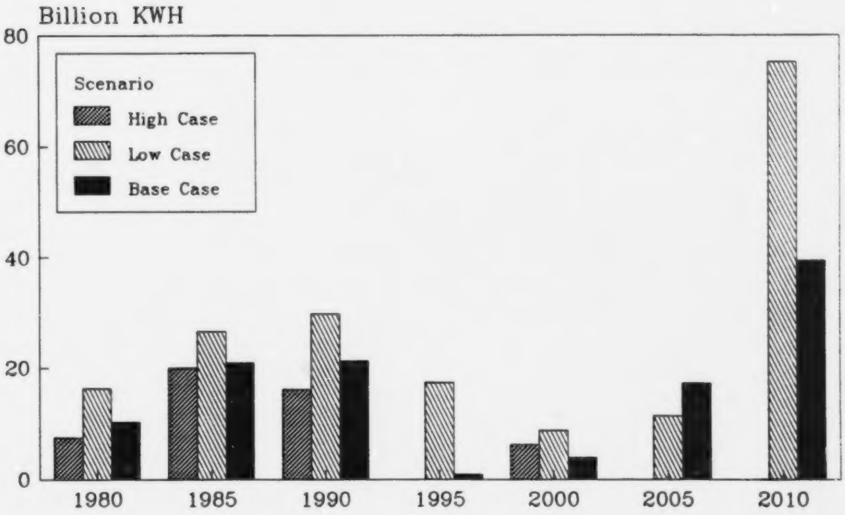


Figure 4.2 Bulk Power Transfers
Transfer Cost Analysis
Region 4: N. & S. Carolina & Virginia



fees is shown to result in the redirection of electricity sources and not generation levels.

4.3 Utility Generating Capacity

Estimates of Low case coal capacity increase above the Base case levels after 2005 while capacity levels are below the Base case prior to 2005. This signifies that additional demand requirements prior to 2005 were met by out-of-state sources until new units could be constructed (Figures 4.4, 4.5 and 4.6 and Table 4.1). Oil and Gas generating capacity displays a greater than 5 percent average per year increase after 1995 in both the High and Low cases compared to the Base case.

Average Percent Change from Base Case

	1985	1990	1995	2000	2005	2009	1985-2009	1995-2009	2000-2009
High Case									
Total	0	3.4	2.9	1.2	0	-1.0	1.5	0.6	-0.2
Coal	0	0	-1.3	-1.2	-2.7	-5.3	-1.1	-2.2	-2.4
Oil & Gas	0	26.7	19.3	7.9	6.5	11.2	12.6	8.8	5.2
Low Case									
Total	-0.2	-1.7	-3.0	0.7	1.5	4.9	0.2	0.8	2.2
Coal	0	0	-5.1	-4.0	-0.8	7.6	-0.6	-1.0	0.8
Oil & Gas	0	13.1	-2.9	11.0	9.0	1.4	1.3	5.3	7.1

- Estimates for Nuclear and Hydro/Other capacity were unchanged from the Base case to the High and Low cases.

Table 4.1 Plant Capacity by Scenario

Lower coal capacity is estimated for the High case while Oil and Gas capacity levels average more than 12 percent above the Base case levels between 1985 and 2009 (Table 4.1). Lower coal capacity estimates associated with the Low case resulted in higher SO_2 emission compared to the Base case because the model decided it was less costly to purchase out-of-state coal fired power than build baseload capacity before 2005. After 2005, SO_2 emissions dropped below the Base levels as lower emitting coal units were added to satisfy higher power transfer levels (Figures 4.2 and 4.3, and Table 4.1). While lower power transfers in the High case decreased the demand for new capacity in the post-2005 period, larger power transfers in the Low case increased demand for capacity compared to the Base case.

Figure 4.3 Coal Unit SO2 Emissions

Transfer Cost Analysis

Region 4: N. & S. Carolina & Virginia

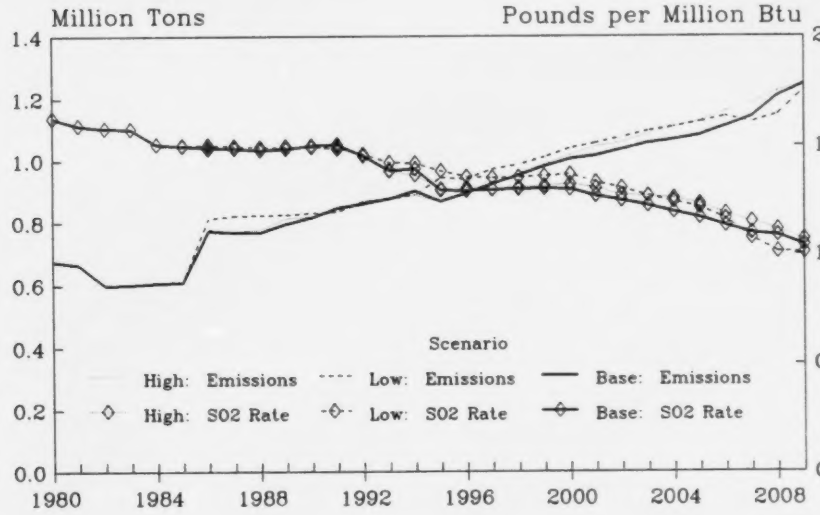


Figure 4.4 Plant Capacity

AUSM Base Scenario

Region 4: N. & S. Carolina & Virginia

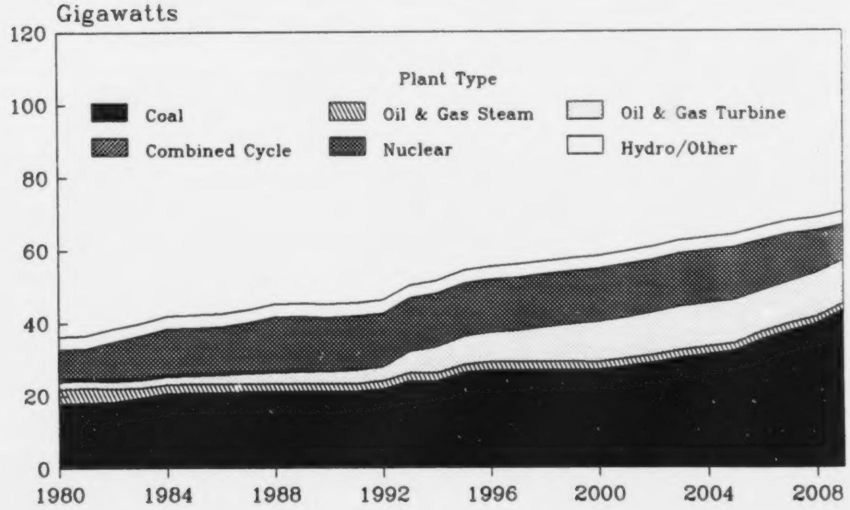


Figure 4.5 Plant Capacity
Transfer Cost Analysis: Low Case
Region 4: N. & S. Carolina & Virginia

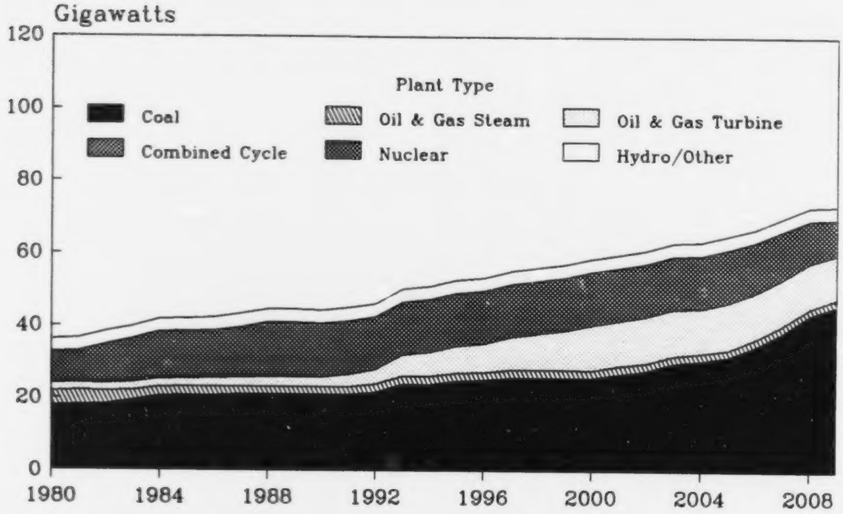
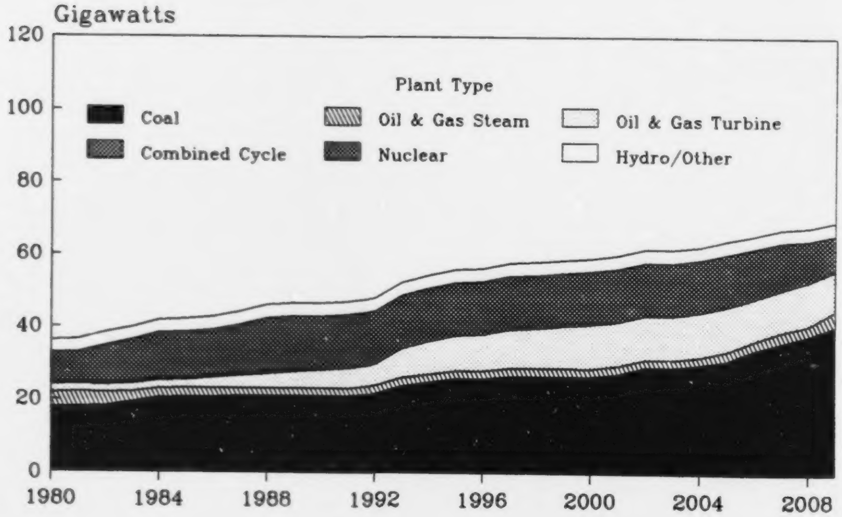


Figure 4.6 Plant Capacity
Transfer Cost Analysis: High Case
Region 4: N. & S. Carolina & Virginia



4.4 Sulfur Dioxide Emissions

As shown in Figure 4.3, changing transfer costs did not have a significant effect on sulfur dioxide emissions from coal units in the VIRCAR region (N. Carolina, S. Carolina, and Virginia). High case SO_2 emissions are approximately equal to Base case levels until 2000. After the year 2000, however, emissions increase over the Base because the demand for electricity is met by additional coal generation (Figure 4.7). This trend reflects increased use of both high and low sulfur coal (Figures 4.8 and 4.10). Consumption of coal with a sulfur content between 1.2 and 2 pounds per MMBtu for both cases is lower than the Base case (see Figure 4.9). Differences in SO_2 emissions across the three scenarios are less than five percent for each year.

4.5 Conclusion

Varying transfer costs had mixed overall effects on modeled utility behavior. Cross scenario changes in state model capacity, generation, and fuel use were minimal because power transfers accounted for only 4 percent of total generation in the High case and just 11 percent of generation in the Low case. More significant cross scenario variation results occurred with respect to MPMS transfer levels. The MPMS summary reports indicated a very strong inverse relationship between transfer costs and the level of power transfers.

Figure 4.7 Generation Comparison
Transfer Cost Analysis
Region 4: N. & S. Carolina & Virginia

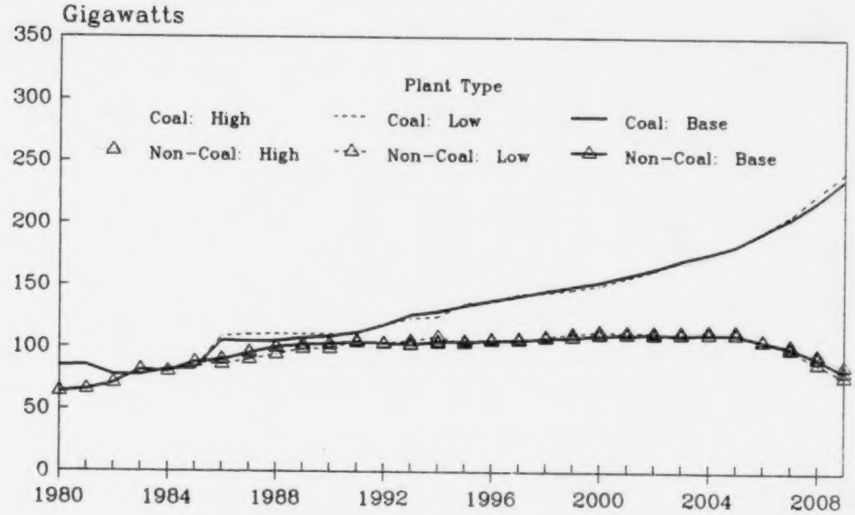


Figure 4.8 Coal Consumption
Transfer Costs: 0 to 1.2 Percent Sulfur
Region 4: N. & S. Carolina & Virginia

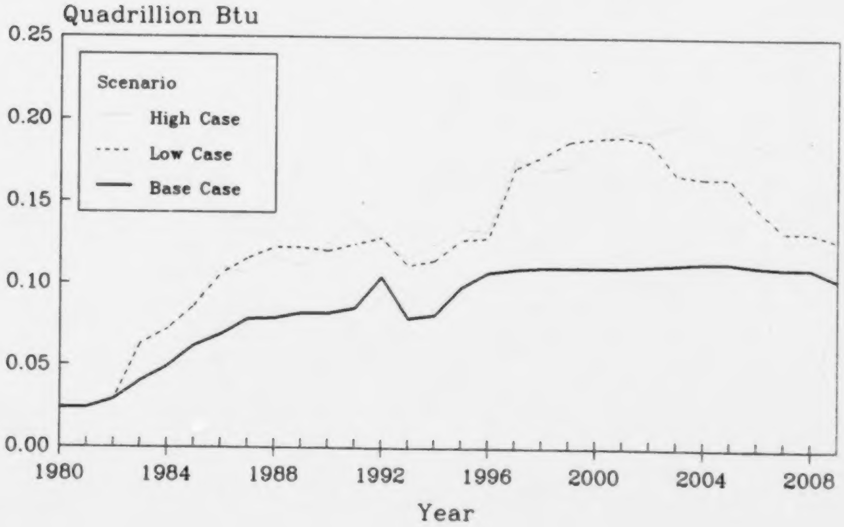


Figure 4.9 Coal Consumption

Transfer Costs: 1.2 to 2 Percent Sulfur

Region 4: N. & S. Carolina & Virginia

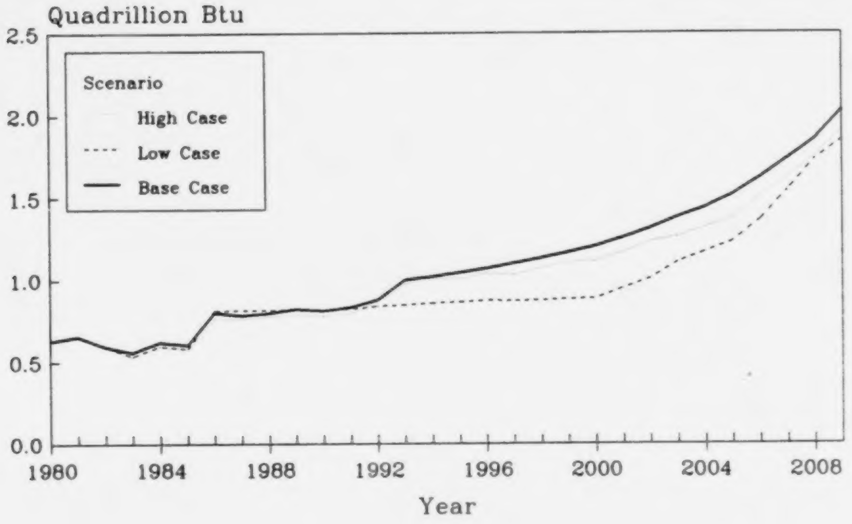
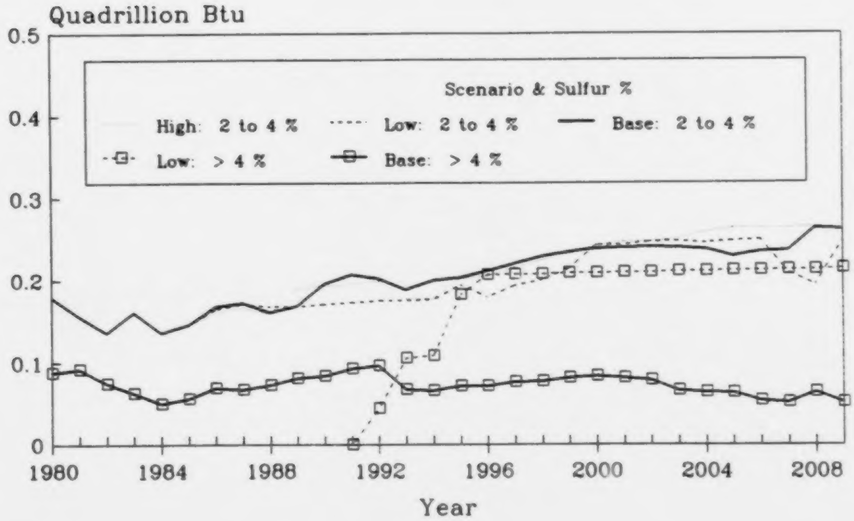


Figure 4.10 Coal Consumption

Transfer Cost Analysis

Region 4: N. & S. Carolina & Virginia



5 CEUM AND HISTORIC DATA COMPARISON WITH AUSM

Comparison of the AUSM projections with historic emissions data and an established model, the ICF, Inc. Coal and Electric Utilities Model (CEUM), emissions projection was a key part of the pre-release testing program for AUSM, Version 3.0. CEUM has been used by EPA and others for analysis of the electric utility industry's emissions and cost of control for more than a decade, and has an established record. Thus, a comparison with the CEUM model was considered to be the most appropriate comparison of model projection outputs for evaluating the status of AUSM.

The inputs to the AUSM and CEUM models were developed around a common set of assumptions which are listed in Appendix C of this report). In addition, some constraints used in the CEUM model were provided by ICF, Inc. for use within the AUSM model. The most notable of these are the generating unit category turn-down ratios and the NO_x emissions factors. These modifications to the AUSM model are described in the AUSM Description of Modifications to the State Level Model report [9].

However, not all constraints or methodologies are common to each model. For example, these models do not have a common data base of coal resources or share the same model structure. Analysis of these differences are beyond the scope of this initial comparison of outputs. Only differences in the compared projection outputs are discussed in this section.

5.1 Inputs

The inputs to the AUSM and CEUM models were set to the values contained in Appendix C to the extent possible, but not all of these data inputs could be readily reconciled between the two models. Even so, a large number of inputs were changed prior to operating the models.

Inputs that were changed to the same value included electricity demand by state, load factors by state, Canadian power imports, oil to coal conversion capacity, the amount of generation by renewables and cogeneration, unit lifetimes, unit heat rates, and oil/gas prices. Inputs that were not adjusted included the amount of hydroelectric, nuclear, coal, oil, gas, turbine, and combined cycle capacity, and the capital, operating and maintenance (fixed and variable) costs of power generation and pollution control equipment. However, a comparison of the cost inputs within AUSM and CEUM was conducted and the differences appeared to be small. Additional information on how these data inputs were incorporated into the AUSM model can be determined by examination of reports in this series for AUSM Version 3.0 and comments in the AUSM model code released with these reports on magnetic tape [see references 8 through 12].

5.2 Emissions

SO_2 and NO_x emissions and emission rate projections from AUSM for each year from 1990 through 2010 are given in Tables 5.1 through 5.8. The results shown for 2010 are an extrapolation since Version 3.0 of AUSM ends its projection with the year 2009. Version 4.0 of AUSM, now undergoing review and which will be documented at a later date, will project emissions through the year 2030. Projections from the CEUM model compared with the AUSM projections are shown in Tables 5.9 through 5.15.

Since the CEUM model provides outputs for selected years (i.e., 1990, 1995, 2000 and 2010), the projections for only these years were compared. In addition, CEUM does not project emissions for years prior to 1990 precluding a comparison with historical data.

The results of the emissions comparisons is summarized by Figure 5.1. The AUSM emissions projection agrees closely with the historical data for the period of 1980 through 1985. No special modifications were made to the AUSM to produce this result. Only the actual electric demand by state for these years was entered as an input to the model. This result implies that the AUSM does adequately predict emissions based on current industry operating practices.

Figure 5.1 also shows the comparison of AUSM and CEUM SO_2 emission projections. The differences in emissions between the CEUM and AUSM outputs are small. And, follow the same general trend of increasing emissions through the year 2010 using these set of inputs. These differences have been examined to determine what factors in the analysis account for them. However, no examination of model structure has been attempted to determine the differences in model methodology that produce these results. Given the small magnitude of the emissions differences, a detailed examination was not given precedence over responding to comments by reviewers on revisions to the AUSM structure.

5.3 Examination of Differences

Emissions projections for 1980 through 1985 from AUSM were compared with the emissions estimates taken from the EPA report "National Air Pollutant Emission Estimation, 1940-1986" [13]. The comparison is shown in Figure 5.1. The emissions data shown as "Actual SO_x" and "Actual NO_x" in this figure are taken from reference 13. The reported emissions for 1980 through 1985 are estimates based in considerable part on fuel use data and emissions factors rather than actual stack gas measurements. The agreement with the AUSM model projections is remarkably good.

Emissions projections for the years 1990, 1995, and 2000 from CEUM were slightly higher than the AUSM projections. The primary reason for this difference can be identified from the generation data comparison shown in Figures 5.2, 5.3 and 5.4. "Actual" generation data in these figures for 1983-1987 are taken from

1987 EPA Base Case (Million Tons)

Region	Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
East	Coal											
	SIP	12.87	12.85	12.85	12.97	13.09	13.24	13.38	13.54	13.69	13.86	14.03
	NSPS	1.08	1.09	1.10	1.12	1.15	1.18	1.21	1.24	1.27	1.30	1.32
	RNSPS	0.12	0.16	0.20	0.26	0.33	0.38	0.44	0.50	0.55	0.61	0.69
	Total Coal	14.08	14.10	14.16	14.35	14.57	14.80	15.03	15.28	15.51	15.77	16.03
	Oil/Gas	1.21	1.19	1.16	1.12	1.05	1.01	0.98	0.96	0.97	0.97	0.95
	Total East	15.29	15.28	15.31	15.47	15.62	15.81	16.00	16.24	16.48	16.74	16.98
West	Coal											
	SIP	0.54	0.54	0.54	0.54	0.54	0.53	0.53	0.53	0.54	0.54	0.54
	NSPS	0.64	0.63	0.64	0.64	0.65	0.66	0.66	0.67	0.68	0.69	0.70
	RNSPS	0.13	0.16	0.18	0.21	0.24	0.26	0.27	0.29	0.30	0.32	0.35
	Total Coal	1.31	1.33	1.36	1.39	1.43	1.44	1.46	1.49	1.52	1.55	1.58
	Oil/Gas	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Total West	1.34	1.36	1.38	1.42	1.45	1.46	1.48	1.51	1.54	1.57	1.60
U.S.	Coal											
	SIP	13.41	13.38	13.39	13.51	13.63	13.77	13.90	14.07	14.22	14.40	14.56
	NSPS	1.72	1.72	1.74	1.77	1.80	1.84	1.87	1.91	1.95	1.98	2.02
	RNSPS	0.26	0.32	0.39	0.47	0.57	0.64	0.72	0.79	0.85	0.94	1.03
	Total Coal	15.39	15.43	15.51	15.74	16.00	16.25	16.49	16.77	17.03	17.32	17.62
	Oil/Gas	1.25	1.21	1.18	1.14	1.08	1.03	1.00	0.98	0.99	0.99	0.97
	Total U.S.	16.63	16.64	16.69	16.89	17.07	17.28	17.49	17.75	18.02	18.31	18.59

Region	Fuel	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
East	Coal										
	SIP	14.22	14.40	14.61	14.78	14.93	15.07	15.20	15.27	15.33	15.39
	NSPS	1.35	1.37	1.40	1.41	1.42	1.43	1.43	1.43	1.43	1.44
	RNSPS	0.76	0.83	0.92	1.03	1.17	1.32	1.51	1.74	2.00	2.29
	Total Coal	16.32	16.61	16.93	17.23	17.52	17.82	18.14	18.44	18.76	19.11
	Oil/Gas	0.93	0.90	0.87	0.84	0.81	0.79	0.77	0.74	0.73	0.71
	Total East	17.26	17.51	17.80	18.06	18.33	18.61	18.91	19.19	19.48	19.83
West	Coal										
	SIP	0.54	0.55	0.56	0.57	0.59	0.60	0.61	0.62	0.63	0.64
	NSPS	0.72	0.74	0.76	0.79	0.81	0.82	0.82	0.83	0.83	0.84
	RNSPS	0.37	0.39	0.42	0.45	0.47	0.49	0.53	0.56	0.61	0.65
	Total Coal	1.63	1.68	1.75	1.81	1.86	1.91	1.96	2.01	2.07	2.13
	Oil/Gas	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	Total West	1.65	1.71	1.77	1.83	1.89	1.94	1.99	2.04	2.09	2.15
U.S.	Coal										
	SIP	14.76	14.95	15.17	15.35	15.52	15.67	15.81	15.89	15.95	16.03
	NSPS	2.06	2.11	2.16	2.20	2.23	2.25	2.26	2.26	2.26	2.27
	RNSPS	1.13	1.23	1.35	1.48	1.63	1.81	2.04	2.31	2.60	2.94
	Total Coal	17.95	18.29	18.67	19.03	19.38	19.73	20.11	20.45	20.82	21.24
	Oil/Gas	0.96	0.93	0.89	0.86	0.84	0.82	0.79	0.77	0.76	0.74
	Total U.S.	18.91	19.22	19.57	19.90	20.22	20.55	20.90	21.22	21.58	21.98

Table 5.1 Utility Sulfur Dioxide Emission Forecasts

1987 EPA Base Case (Million Tons)

Region	Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
East	Coal											
	SIP	3.75	3.77	3.79	3.82	3.85	3.90	3.94	3.99	4.04	4.10	4.16
	NSPS	0.72	0.72	0.73	0.74	0.76	0.78	0.80	0.82	0.84	0.85	0.87
	RNSPS	0.13	0.17	0.22	0.28	0.36	0.42	0.49	0.55	0.61	0.68	0.76
	Total Coal	4.60	4.66	4.74	4.84	4.97	5.09	5.22	5.36	5.49	5.63	5.78
	Oil/Gas	0.88	0.87	0.86	0.84	0.81	0.78	0.77	0.77	0.77	0.78	0.78
	Total East	5.48	5.53	5.59	5.68	5.78	5.88	5.99	6.13	6.26	6.41	6.56
West	Coal											
	SIP	0.34	0.35	0.35	0.36	0.36	0.37	0.37	0.38	0.38	0.38	0.39
	NSPS	0.53	0.52	0.52	0.53	0.54	0.54	0.55	0.55	0.56	0.57	0.58
	RNSPS	0.23	0.27	0.31	0.36	0.40	0.43	0.46	0.48	0.51	0.54	0.58
	Total Coal	1.10	1.14	1.18	1.24	1.30	1.34	1.38	1.41	1.45	1.50	1.55
	Oil/Gas	0.55	0.55	0.55	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.56
	Total West	1.65	1.69	1.73	1.78	1.84	1.88	1.92	1.96	2.00	2.05	2.10
U.S.	Coal											
	SIP	4.10	4.12	4.14	4.18	4.22	4.26	4.31	4.36	4.42	4.49	4.54
	NSPS	1.24	1.24	1.25	1.27	1.30	1.32	1.34	1.37	1.40	1.43	1.45
	RNSPS	0.36	0.44	0.53	0.64	0.76	0.85	0.95	1.04	1.12	1.22	1.34
	Total Coal	5.70	5.80	5.92	6.09	6.27	6.43	6.60	6.77	6.94	7.13	7.33
	Oil/Gas	1.43	1.42	1.41	1.38	1.34	1.32	1.32	1.31	1.33	1.33	1.33
	Total U.S.	7.13	7.22	7.32	7.47	7.61	7.76	7.91	8.09	8.27	8.46	8.67

Region	Fuel	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
East	Coal										
	SIP	4.22	4.28	4.33	4.38	4.42	4.46	4.50	4.52	4.53	4.55
	NSPS	0.88	0.90	0.92	0.93	0.94	0.95	0.95	0.95	0.95	0.95
	RNSPS	0.83	0.93	1.03	1.16	1.32	1.50	1.72	1.99	2.28	2.62
	Total Coal	5.94	6.10	6.28	6.47	6.68	6.91	7.17	7.45	7.76	8.12
	Oil/Gas	0.77	0.76	0.76	0.74	0.73	0.72	0.70	0.69	0.67	0.66
	Total East	6.71	6.86	7.03	7.22	7.41	7.63	7.88	8.14	8.44	8.78
West	Coal										
	SIP	0.39	0.39	0.40	0.41	0.42	0.42	0.43	0.44	0.44	0.45
	NSPS	0.60	0.62	0.64	0.66	0.68	0.69	0.69	0.70	0.70	0.70
	RNSPS	0.62	0.65	0.69	0.72	0.74	0.78	0.82	0.86	0.91	0.96
	Total Coal	1.60	1.66	1.72	1.78	1.84	1.88	1.94	1.99	2.05	2.12
	Oil/Gas	0.56	0.56	0.56	0.57	0.57	0.56	0.55	0.54	0.52	0.49
	Total West	2.16	2.22	2.29	2.35	2.40	2.45	2.49	2.53	2.57	2.61
U.S.	Coal										
	SIP	4.61	4.67	4.73	4.79	4.84	4.88	4.92	4.95	4.97	5.00
	NSPS	1.48	1.52	1.55	1.59	1.61	1.63	1.64	1.64	1.65	1.66
	RNSPS	1.45	1.58	1.72	1.88	2.06	2.28	2.54	2.85	3.19	3.58
	Total Coal	7.54	7.76	8.00	8.26	8.52	8.80	9.11	9.45	9.82	10.23
	Oil/Gas	1.33	1.33	1.32	1.31	1.30	1.28	1.25	1.23	1.19	1.16
	Total U.S.	8.87	9.09	9.32	9.57	9.82	10.08	10.37	10.67	11.01	11.39

Table 5.2 Utility Nitrogen Oxides Emission Forecasts

1987 EPA Base Case (Million Tons)

Region	Fuel/Technology	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
East	Coal SIP	3.27	3.25	3.23	3.24	3.24	3.24	3.24	3.24	3.23	3.22	3.21
	Coal NSPS	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.98
	Coal RNSPS	0.57	0.57	0.57	0.56	0.56	0.55	0.55	0.55	0.55	0.55	0.55
	Total Coal	2.67	2.63	2.59	2.55	2.51	2.47	2.43	2.40	2.36	2.33	2.30
	Oil/Gas	0.84	0.82	0.80	0.78	0.75	0.72	0.70	0.69	0.68	0.67	0.65
	Total East	2.28	2.25	2.21	2.19	2.16	2.14	2.11	2.09	2.06	2.04	2.02
West	Coal SIP	1.12	1.13	1.13	1.13	1.12	1.11	1.11	1.11	1.11	1.11	1.10
	Coal NSPS	0.77	0.77	0.78	0.78	0.79	0.79	0.79	0.79	0.79	0.79	0.79
	Coal RNSPS	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
	Total Coal	0.78	0.76	0.75	0.74	0.73	0.71	0.71	0.70	0.69	0.69	0.68
	Oil/Gas	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
	Total West	0.50	0.49	0.49	0.49	0.49	0.48	0.48	0.48	0.48	0.47	0.47
U.S.	Coal SIP	3.03	3.02	3.01	3.01	3.02	3.02	3.02	3.02	3.01	3.00	3.00
	Coal NSPS	0.88	0.89	0.89	0.89	0.89	0.90	0.90	0.90	0.90	0.90	0.90
	Coal RNSPS	0.43	0.43	0.44	0.44	0.45	0.46	0.46	0.46	0.46	0.46	0.47
	Total Coal	2.21	2.17	2.13	2.10	2.06	2.03	2.00	1.97	1.95	1.92	1.89
	Oil/Gas	0.51	0.49	0.47	0.47	0.45	0.43	0.41	0.41	0.40	0.40	0.39
	Total U.S.	1.77	1.74	1.71	1.69	1.67	1.66	1.64	1.62	1.61	1.59	1.57

Region	Fuel/Technology	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
East	Coal SIP	3.21	3.20	3.21	3.21	3.21	3.21	3.22	3.22	3.23	3.23
	Coal NSPS	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.97	0.97	0.97
	Coal RNSPS	0.55	0.54	0.54	0.53	0.53	0.53	0.52	0.52	0.51	0.51
	Total Coal	2.27	2.23	2.20	2.16	2.11	2.06	2.00	1.93	1.86	1.80
	Oil/Gas	0.64	0.61	0.59	0.56	0.55	0.53	0.51	0.50	0.49	0.48
	Total East	1.99	1.97	1.94	1.91	1.87	1.83	1.79	1.74	1.69	1.64
West	Coal SIP	1.10	1.11	1.11	1.12	1.12	1.12	1.12	1.11	1.10	1.10
	Coal NSPS	0.79	0.80	0.80	0.80	0.80	0.80	0.80	0.79	0.79	0.79
	Coal RNSPS	0.36	0.36	0.37	0.37	0.38	0.38	0.38	0.39	0.40	0.40
	Total Coal	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.66	0.66	0.65
	Oil/Gas	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
	Total West	0.47	0.48	0.48	0.48	0.49	0.49	0.49	0.50	0.50	0.51
U.S.	Coal SIP	3.00	2.99	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
	Coal NSPS	0.90	0.91	0.91	0.90	0.90	0.90	0.90	0.90	0.90	0.89
	Coal RNSPS	0.47	0.47	0.47	0.47	0.47	0.47	0.48	0.48	0.48	0.48
	Total Coal	1.87	1.84	1.81	1.78	1.75	1.71	1.67	1.62	1.58	1.53
	Oil/Gas	0.38	0.36	0.35	0.34	0.33	0.32	0.31	0.31	0.30	0.30
	Total U.S.	1.56	1.54	1.52	1.50	1.48	1.46	1.43	1.40	1.37	1.34

Table 5.3 Utility Sulfur Dioxide Emission Rate Forecasts

1987 EPA Base Case (Pounds NOx/MMBtu)

Region	Fuel/Technology	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
East	Coal SIP	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
	Coal NSPS	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
	Coal RNSPS	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
	Total Coal	0.87	0.87	0.87	0.86	0.85	0.85	0.84	0.84	0.84	0.83	0.83
	Oil/Gas	0.61	0.60	0.59	0.58	0.57	0.56	0.55	0.55	0.55	0.54	0.54
	Total East	0.82	0.81	0.81	0.80	0.80	0.79	0.79	0.79	0.78	0.78	0.78
West	Coal SIP	0.72	0.72	0.73	0.75	0.76	0.77	0.78	0.79	0.79	0.79	0.79
	Coal NSPS	0.63	0.63	0.64	0.64	0.65	0.65	0.65	0.65	0.66	0.66	0.66
	Coal RNSPS	0.60	0.60	0.60	0.61	0.61	0.61	0.61	0.61	0.60	0.60	0.60
	Total Coal	0.65	0.65	0.65	0.66	0.66	0.66	0.67	0.67	0.67	0.67	0.66
	Oil/Gas	0.55	0.54	0.54	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53
	Total West	0.61	0.61	0.61	0.61	0.62	0.62	0.62	0.62	0.62	0.62	0.62
U.S.	Coal SIP	0.93	0.93	0.93	0.93	0.93	0.94	0.94	0.94	0.94	0.94	0.94
	Coal NSPS	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.65	0.65	0.65	0.65
	Coal RNSPS	0.60	0.60	0.60	0.60	0.61	0.60	0.60	0.60	0.60	0.60	0.60
	Total Coal	0.82	0.82	0.81	0.81	0.81	0.80	0.80	0.80	0.79	0.79	0.79
	Oil/Gas	0.59	0.58	0.57	0.56	0.56	0.55	0.54	0.54	0.54	0.54	0.53
	Total U.S.	0.76	0.75	0.75	0.75	0.75	0.74	0.74	0.74	0.74	0.73	0.73

Region	Fuel/Technology	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
East	Coal SIP	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
	Coal NSPS	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
	Coal RNSPS	0.60	0.60	0.60	0.60	0.60	0.59	0.59	0.59	0.59	0.58
	Total Coal	0.82	0.82	0.81	0.81	0.80	0.80	0.79	0.78	0.77	0.76
	Oil/Gas	0.53	0.52	0.51	0.50	0.49	0.48	0.47	0.47	0.46	0.45
	Total East	0.78	0.77	0.77	0.76	0.76	0.75	0.74	0.74	0.73	0.72
West	Coal SIP	0.79	0.79	0.79	0.79	0.79	0.79	0.79	0.78	0.78	0.78
	Coal NSPS	0.66	0.66	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
	Coal RNSPS	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.59	0.59
	Total Coal	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.65	0.65
	Oil/Gas	0.53	0.53	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.51
	Total West	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
U.S.	Coal SIP	0.94	0.94	0.94	0.94	0.93	0.94	0.94	0.94	0.94	0.94
	Coal NSPS	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
	Coal RNSPS	0.60	0.60	0.60	0.60	0.60	0.60	0.59	0.59	0.59	0.59
	Total Coal	0.78	0.78	0.78	0.77	0.77	0.76	0.76	0.75	0.74	0.73
	Oil/Gas	0.53	0.52	0.52	0.51	0.50	0.50	0.49	0.49	0.48	0.47
	Total U.S.	0.73	0.73	0.72	0.72	0.72	0.71	0.71	0.70	0.70	0.69

Table 5.4 Utility Nitrogen Oxides Emission Rate Forecasts

1987 EPA Base Case (Gigawatts)

Region	Fuel/Technology	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
East	Coal											
	Coal SIP	172.73	172.70	172.66	172.62	172.56	172.50	172.42	172.34	172.23	172.06	171.83
	Coal NSPS	51.46	51.75	52.04	52.39	52.88	53.37	53.87	54.36	54.50	54.75	55.00
	Coal RNSPS	9.51	12.20	15.12	19.05	23.53	27.62	32.26	36.62	40.35	44.70	49.61
	Total Coal	233.72	236.65	239.82	244.06	248.97	253.49	258.55	263.32	267.08	271.51	276.44
	Oil/Gas	116.45	120.38	125.07	130.18	135.84	142.44	145.24	147.58	149.85	151.53	152.61
	Nuclear	86.68	87.57	88.02	88.48	88.69	88.89	89.09	89.04	88.99	88.98	88.97
	Hydro/Other	21.85	22.07	22.58	23.06	23.37	23.66	23.94	23.94	23.94	23.94	23.94
	Total East	458.70	466.67	475.49	485.78	496.87	508.48	516.82	523.88	529.86	535.96	541.96
West	Coal											
	Coal SIP	21.81	21.81	21.81	21.81	21.81	21.81	21.81	21.81	21.80	21.79	21.78
	Coal NSPS	36.66	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69
	Coal RNSPS	16.33	18.85	21.47	23.68	25.46	26.49	27.33	28.38	29.72	31.63	34.00
	Total Coal	74.80	77.35	79.97	82.18	83.96	84.99	85.83	86.88	88.21	90.11	92.47
	Oil/Gas	85.61	85.98	86.40	87.24	88.37	89.90	91.21	92.38	93.31	93.76	93.90
	Nuclear	18.70	18.95	19.20	19.20	19.26	19.57	19.86	20.16	20.46	20.70	20.69
	Hydro/Other	50.39	50.50	50.61	50.72	50.76	50.80	50.83	50.86	50.90	50.90	50.91
	Total West	229.50	232.78	236.18	239.34	242.35	245.26	247.73	250.28	252.88	255.47	257.97
U.S.	Coal											
	Coal SIP	194.54	194.51	194.47	194.43	194.37	194.31	194.23	194.15	194.03	193.85	193.61
	Coal NSPS	88.12	88.44	88.73	89.08	89.57	90.06	90.56	91.05	91.19	91.44	91.69
	Coal RNSPS	25.86	31.05	36.59	42.73	48.99	54.11	59.59	65.00	70.07	76.33	83.61
	Total Coal	308.52	314.00	319.79	326.24	332.93	338.48	344.38	350.20	355.29	361.62	368.91
	Oil/Gas	202.06	206.36	211.47	217.42	224.21	232.34	236.45	239.96	243.16	245.29	246.51
	Nuclear	105.38	106.52	107.22	107.68	107.95	108.46	108.95	109.20	109.45	109.68	109.66
	Hydro/Other	72.24	72.57	73.19	73.78	74.13	74.46	74.77	74.80	74.84	74.84	74.85
	Total U.S.	688.20	699.45	711.67	725.12	739.22	753.74	764.55	774.16	782.74	791.43	799.93

Table 5.5 Utility Power Plant Capacity Forecasts

1987 EPA Base Case (Gigawatts)

Region	Fuel	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
East	Coal										
	Coal SIP	171.53	171.19	170.87	170.62	170.40	170.07	169.30	167.69	165.22	161.95
	Coal NSPS	55.25	55.50	55.75	55.75	55.75	55.75	55.75	55.75	55.75	55.75
	Coal RNSPS	54.49	60.49	67.27	75.82	87.00	99.81	115.45	134.79	156.71	181.67
	Total Coal	281.27	287.18	293.89	302.19	313.15	325.63	340.50	358.23	377.68	399.37
	Oil/Gas	153.26	153.70	154.41	154.78	153.64	152.36	150.71	147.89	144.78	142.34
	Nuclear	88.86	88.49	87.77	86.40	84.25	80.93	76.15	69.18	60.32	49.72
	Hydro/Other	23.94	23.94	23.95	23.96	23.98	23.99	24.00	24.00	24.00	24.00
	Total East	547.33	553.31	560.02	567.33	575.02	582.91	591.36	599.30	606.78	615.43
West	Coal										
	Coal SIP	21.77	21.76	21.74	21.73	21.71	21.70	21.67	21.65	21.64	21.62
	Coal NSPS	36.66	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69
	Coal RNSPS	36.17	37.93	39.74	41.00	42.09	43.84	46.17	48.60	51.44	54.49
	Total Coal	94.60	96.38	98.17	99.42	100.49	102.23	104.53	106.94	109.77	112.80
	Oil/Gas	94.16	94.44	94.55	94.77	94.77	94.28	93.02	91.11	88.60	85.57
	Nuclear	20.60	20.52	20.43	20.35	20.26	20.26	20.01	19.76	19.51	19.26
	Hydro/Other	50.91	50.96	51.09	51.23	51.36	51.50	51.60	51.61	51.61	51.62
	Total West	260.27	262.30	264.24	265.77	266.88	268.27	269.16	269.42	269.49	269.25
U.S.	Coal										
	Coal SIP	193.30	192.95	192.61	192.35	192.11	191.77	190.97	189.34	186.86	183.57
	Coal NSPS	91.91	92.19	92.44	92.44	92.44	92.44	92.44	92.44	92.44	92.44
	Coal RNSPS	90.66	98.42	107.01	116.82	129.09	143.65	161.62	183.39	208.15	236.16
	Total Coal	375.87	383.56	392.06	401.61	413.64	427.86	445.03	465.17	487.45	512.17
	Oil/Gas	247.42	248.14	248.96	249.55	248.41	246.64	243.73	239.00	233.38	227.91
	Nuclear	109.46	109.01	108.20	106.75	104.51	101.19	96.16	88.94	79.83	68.98
	Hydro/Other	74.85	74.90	75.04	75.19	75.34	75.49	75.60	75.61	75.61	75.62
	Total U.S.	807.60	815.61	824.26	833.10	841.90	851.18	860.52	868.72	876.27	884.68

Table 5.5 Utility Power Plant Capacity Forecasts (continued)

1987 EPA Base Case (Billion kWh)

Region	Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
East	Coal											
	Coal SIP	747.7	749.0	751.7	756.5	762.1	769.9	778.0	787.9	798.7	809.8	820.7
	Coal NSPS	218.8	220.3	222.8	226.8	232.3	237.3	242.9	248.6	253.7	257.4	261.6
	Coal RNSPS	43.5	57.5	72.8	94.4	120.1	141.3	164.0	186.2	205.0	227.4	253.5
	Total Coal	1010.0	1026.9	1047.3	1077.6	1114.5	1148.6	1184.9	1222.7	1257.4	1294.6	1335.7
	Oil/Gas	254.0	254.7	255.6	253.6	247.9	246.1	244.2	244.2	247.8	250.6	251.5
	Nuclear	487.6	496.6	503.6	507.2	508.5	510.2	510.9	510.0	510.4	511.5	512.2
	Hydro/Other	66.8	67.4	68.8	70.2	71.2	72.2	72.9	72.9	72.9	73.0	73.0
	Total East	1818.5	1845.5	1875.3	1908.7	1942.1	1977.0	2012.9	2049.7	2088.5	2129.7	2172.3
West	Coal											
	Coal SIP	84.9	84.1	82.9	83.6	84.1	83.1	82.9	83.4	83.8	83.8	84.2
	Coal NSPS	155.9	154.0	153.4	153.9	154.5	155.0	155.8	156.7	158.9	160.9	163.0
	Coal RNSPS	73.0	85.7	99.1	112.8	126.3	135.7	149.9	151.7	159.9	170.6	183.2
	Total Coal	313.8	323.8	335.4	350.3	364.9	373.7	388.5	391.8	402.5	415.4	430.4
	Oil/Gas	187.8	189.0	190.4	188.6	186.9	188.6	190.0	190.9	192.7	194.1	195.4
	Nuclear	97.3	99.8	101.8	102.0	102.4	103.3	104.0	104.6	105.3	105.9	106.0
	Hydro/Other	222.0	224.8	227.5	231.8	235.7	238.6	241.3	243.6	243.5	243.3	243.0
	Total West	821.0	837.3	855.0	872.7	889.8	904.2	923.8	930.9	943.9	958.6	974.8
U.S.	Coal											
	Coal SIP	832.6	833.1	834.6	840.1	846.2	853.0	860.8	871.2	882.4	893.6	904.8
	Coal NSPS	374.7	374.3	376.2	380.7	386.8	392.3	398.7	405.3	412.6	418.3	424.6
	Coal RNSPS	116.5	143.2	171.9	207.1	246.4	277.0	313.9	337.9	364.9	398.1	436.7
	Total Coal	1323.8	1350.6	1382.7	1427.9	1479.4	1522.3	1573.4	1614.4	1659.9	1710.0	1766.1
	Oil/Gas	441.9	443.6	445.9	442.2	434.8	434.7	434.2	435.2	440.5	444.7	446.9
	Nuclear	585.0	596.4	605.4	609.2	610.9	613.5	614.9	614.6	615.7	617.4	618.2
	Hydro/Other	288.8	292.2	296.3	302.0	306.9	310.8	314.2	316.5	316.4	316.2	316.0
	Total U.S.	2639.5	2682.9	2730.3	2781.4	2831.9	2881.2	2936.8	2980.6	3032.4	3088.3	3147.1

Table 5.6 Electricity Generation Forecasts

1987 EPA Base Case (Billion kWh)

Region	Fuel	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
East	Coal										
	Coal SIP	832.2	842.7	852.9	861.9	869.1	876.2	881.9	885.9	889.5	893.6
	Coal NSPS	265.1	269.2	274.1	277.3	278.6	279.9	279.9	278.3	277.5	277.6
	Coal RNSPS	279.6	309.9	346.1	389.7	444.3	507.5	585.2	677.5	781.6	899.8
	Total Coal	1376.8	1421.8	1473.0	1529.0	1591.9	1663.5	1747.0	1841.7	1948.7	2070.9
	Oil/Gas	252.6	253.4	254.1	254.7	254.5	254.6	253.9	252.4	251.6	251.8
	Nuclear	512.7	511.3	506.7	498.1	485.3	465.0	436.1	395.8	344.4	282.4
	Hydro/Other	73.0	73.1	73.1	73.1	73.1	73.1	72.9	72.7	72.5	72.2
	Total East	2215.2	2259.7	2306.9	2354.9	2404.9	2456.2	2509.9	2562.6	2617.2	2677.3
West	Coal										
	Coal SIP	84.7	85.5	86.7	88.8	90.9	92.5	94.3	96.1	98.1	100.0
	Coal NSPS	166.6	170.8	175.0	179.1	183.2	185.4	187.3	188.4	189.3	190.5
	Coal RNSPS	194.8	205.3	217.5	226.8	234.7	245.5	260.0	274.5	291.1	308.9
	Total Coal	446.0	461.7	479.2	494.7	508.8	523.4	541.7	559.1	578.5	599.5
	Oil/Gas	197.4	199.6	200.3	201.6	202.7	201.9	198.3	194.9	190.3	185.0
	Nuclear	106.4	107.5	108.9	110.0	110.9	111.5	110.6	108.6	106.1	103.1
	Hydro/Other	242.8	242.9	244.0	245.0	245.9	246.8	247.4	247.6	247.7	247.9
	Total West	992.7	1011.7	1032.3	1051.3	1068.4	1083.6	1097.9	1110.1	1122.6	1135.5
U.S.	Coal										
	Coal SIP	916.8	928.2	939.6	950.7	959.9	968.7	976.2	982.0	987.6	993.6
	Coal NSPS	431.7	440.0	449.0	456.4	461.7	465.3	467.2	466.7	466.8	468.1
	Coal RNSPS	474.3	515.2	563.6	616.5	679.0	753.0	845.3	952.0	1072.7	1208.7
	Total Coal	1822.9	1883.4	1952.2	2023.6	2100.6	2186.9	2288.7	2400.7	2527.1	2670.4
	Oil/Gas	450.0	453.0	454.4	456.3	457.3	456.6	452.2	447.3	441.9	436.8
	Nuclear	619.2	618.8	615.5	608.1	596.3	576.6	546.6	504.4	450.5	385.5
	Hydro/Other	315.8	316.0	317.1	318.1	319.1	319.8	320.3	320.3	320.2	320.1
	Total U.S.	3207.9	3271.3	3339.2	3406.1	3473.2	3539.9	3607.8	3672.7	3739.8	3812.8

Table 5.6 Electricity Generation Forecasts (continued)

1987 EPA Base Case (Quadrillion Btu)

Region	Fuel/Technology	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
East	Coal											
	(0.0,1.2)	1.57	1.59	1.61	1.66	1.70	1.73	1.78	1.83	1.87	1.91	1.95
	(1.2,2.0)	2.86	2.97	3.08	3.25	3.44	3.61	3.77	3.93	4.06	4.22	4.43
	(2.0,4.0)	2.61	2.62	2.65	2.67	2.70	2.75	2.81	2.88	2.94	3.01	3.08
	(over 4.0)	3.48	3.53	3.59	3.68	3.79	3.90	4.00	4.13	4.25	4.38	4.50
	Total Coal	10.53	10.71	10.93	11.25	11.63	11.99	12.36	12.76	13.13	13.52	13.96
	Oil	1.98	1.94	1.90	1.85	1.76	1.69	1.66	1.64	1.65	1.64	1.63
	Gas	0.89	0.94	1.00	1.03	1.06	1.11	1.13	1.16	1.19	1.24	1.27
	Total East	13.40	13.59	13.83	14.13	14.45	14.79	15.15	15.55	15.97	16.40	16.86
West	Coal											
	(0.0,1.2)	2.19	2.28	2.39	2.52	2.65	2.73	2.81	2.88	2.96	3.05	3.14
	(1.2,2.0)	0.81	0.84	0.87	0.92	0.98	1.01	1.03	1.07	1.10	1.15	1.23
	(2.0,4.0)	0.34	0.32	0.29	0.26	0.23	0.22	0.22	0.22	0.22	0.22	0.21
	(over 4.0)	0.04	0.05	0.06	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.09
	Total Coal	3.38	3.49	3.62	3.78	3.94	4.04	4.14	4.25	4.36	4.51	4.67
	Oil	0.21	0.17	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
	Gas	1.80	1.86	1.91	1.90	1.88	1.90	1.91	1.92	1.94	1.96	1.97
	Total West	5.40	5.52	5.67	5.81	5.96	6.07	6.19	6.31	6.44	6.60	6.78
U.S.	Coal											
	(0.0,1.2)	3.76	3.88	4.00	4.18	4.35	4.46	4.58	4.70	4.84	4.96	5.09
	(1.2,2.0)	3.67	3.81	3.96	4.17	4.41	4.62	4.80	5.00	5.16	5.38	5.66
	(2.0,4.0)	2.95	2.94	2.94	2.93	2.93	2.97	3.03	3.10	3.16	3.23	3.29
	(over 4.0)	3.52	3.58	3.66	3.76	3.88	3.98	4.09	4.21	4.34	4.47	4.59
	Total Coal	13.91	14.21	14.55	15.03	15.57	16.02	16.50	17.01	17.49	18.03	18.63
	Oil	2.19	2.11	2.04	1.99	1.90	1.83	1.79	1.78	1.78	1.78	1.77
	Gas	2.69	2.80	2.91	2.92	2.94	3.01	3.05	3.08	3.13	3.19	3.24
	Total U.S.	18.80	19.12	19.50	19.94	20.41	20.86	21.34	21.86	22.41	23.01	23.64

Table 5.7 Utility Fuel Consumption Forecasts

1987 EPA Base Case (Quadrillion Btu)

Region	Fuel/Technology	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
East	Coal										
	(0.0,1.2)	1.98	2.01	2.05	2.10	2.16	2.22	2.30	2.35	2.41	2.46
	(1.2,2.0)	4.67	4.97	5.32	5.72	6.17	6.68	7.26	7.91	8.56	9.24
	(2.0,4.0)	3.14	3.20	3.26	3.31	3.34	3.38	3.44	3.50	3.56	3.64
	(over 4.0)	4.60	4.69	4.78	4.87	4.98	5.09	5.22	5.34	5.47	5.58
	Total Coal	14.39	14.87	15.41	16.00	16.64	17.38	18.21	19.10	20.00	20.93
	Oil	1.61	1.57	1.53	1.49	1.45	1.41	1.37	1.32	1.28	1.25
	Gas	1.32	1.37	1.43	1.49	1.53	1.57	1.61	1.64	1.67	1.70
	Total East	17.31	17.81	18.37	18.98	19.63	20.36	21.19	22.06	22.95	23.87
West	Coal										
	(0.0,1.2)	3.23	3.31	3.39	3.46	3.52	3.55	3.58	3.60	3.61	3.63
	(1.2,2.0)	1.32	1.40	1.51	1.59	1.66	1.74	1.85	1.96	2.08	2.22
	(2.0,4.0)	0.21	0.20	0.21	0.23	0.26	0.31	0.37	0.44	0.53	0.63
	(4.0,)	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11
	Total Coal	4.84	5.01	5.21	5.38	5.54	5.71	5.91	6.10	6.33	6.58
	Oil	0.14	0.15	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18
	Gas	1.98	2.00	2.00	2.01	2.01	2.00	1.96	1.91	1.84	1.75
	Total West	6.97	7.16	7.37	7.55	7.72	7.88	8.04	8.19	8.34	8.51
U.S.	Coal										
	(0.0,1.2)	5.21	5.32	5.44	5.56	5.68	5.78	5.88	5.95	6.02	6.09
	(1.2,2.0)	5.99	6.38	6.83	7.31	7.82	8.42	9.11	9.87	10.64	11.46
	(2.0,4.0)	3.35	3.41	3.47	3.54	3.60	3.69	3.80	3.94	4.09	4.27
	(4.0,)	4.69	4.78	4.88	4.97	5.08	5.19	5.33	5.45	5.57	5.69
	Total Coal	19.24	19.88	20.62	21.38	22.18	23.08	24.12	25.20	26.33	27.51
	Oil	1.75	1.72	1.69	1.66	1.62	1.58	1.54	1.50	1.46	1.42
	Gas	3.30	3.37	3.43	3.49	3.55	3.57	3.56	3.54	3.50	3.45
	Total U.S.	24.29	24.98	25.74	26.53	27.35	28.24	29.23	30.24	31.29	32.39

Table 5.7 Utility Fuel Consumption Forecasts (continued)

1987 EPA Base Case (Percent)

Region	Fuel/Technology	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
East	Coal											
	Coal SIP	49.4	49.5	49.7	50.0	50.4	50.9	51.5	52.2	52.9	53.7	54.5
	Coal NSPS	48.5	48.6	48.8	49.4	50.1	50.7	51.4	52.2	53.1	53.6	54.3
	Coal RNSPS	52.1	53.8	54.9	56.5	58.2	58.4	58.0	58.0	58.0	58.0	58.2
	Total Coal	49.3	49.5	49.8	50.4	51.1	51.7	52.3	53.0	53.7	54.4	55.1
	Oil/Gas	24.9	24.1	23.3	22.2	20.8	19.7	19.2	18.9	18.9	18.9	18.8
	Nuclear	64.2	64.7	65.3	65.4	65.4	65.5	65.4	65.3	65.4	65.6	65.7
	Hydro/Other	34.9	34.8	34.8	34.7	34.7	34.8	34.8	34.7	34.7	34.8	34.8
	Total East	45.2	45.1	45.0	44.8	44.6	44.4	44.4	44.6	45.0	45.3	45.7
West	Coal											
	Coal SIP	44.4	44.0	43.3	43.7	44.0	43.4	43.3	43.6	43.8	43.9	44.1
	Coal NSPS	48.5	47.9	47.7	47.8	48.0	48.2	48.4	48.7	49.4	50.0	50.7
	Coal RNSPS	51.0	51.9	52.7	54.3	56.6	58.4	60.1	61.0	61.4	61.6	61.5
	Total Coal	47.9	47.7	47.8	48.6	49.6	50.2	50.8	51.4	52.1	52.6	53.1
	Oil/Gas	25.0	25.1	25.1	24.7	24.1	23.9	23.8	23.6	23.6	23.6	23.7
	Nuclear	59.4	60.1	60.5	60.6	60.6	60.2	59.7	59.2	58.7	58.3	58.5
	Hydro/Other	50.3	50.8	51.3	52.1	53.0	53.6	54.2	54.6	54.6	54.5	54.5
	Total East	40.8	41.0	41.3	41.6	41.9	42.1	42.3	42.4	42.6	42.8	43.1
U.S.	Coal											
	Coal SIP	48.8	48.9	49.0	49.3	49.7	50.1	50.6	51.2	51.9	52.6	53.3
	Coal NSPS	48.5	48.3	48.4	48.7	49.3	49.7	50.2	50.8	51.6	52.2	52.8
	Coal RNSPS	51.4	52.6	53.6	55.3	57.4	58.4	58.9	59.3	59.4	59.5	59.6
	Total Coal	48.9	49.1	49.3	49.9	50.7	51.3	51.9	52.6	53.3	53.9	54.6
	Oil/Gas	24.9	24.5	24.1	23.2	22.1	21.3	20.9	20.7	20.7	20.7	20.7
	Nuclear	63.3	63.9	64.4	64.5	64.6	64.5	64.4	64.2	64.2	64.2	64.3
	Hydro/Other	45.6	45.9	46.2	46.7	47.2	47.6	47.9	48.3	48.2	48.2	48.2
	Total U.S.	43.8	43.8	43.8	43.8	43.7	43.6	43.7	43.9	44.2	44.5	44.9

Table 5.8 Capacity Factors

1987 EPA Base Case (Percent)

Region	Fuel/Technology	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
East	Coal										
	Coal SIP	55.3	56.2	56.9	57.6	58.2	58.8	59.4	60.3	61.4	62.9
	Coal NSPS	54.7	55.3	56.1	56.7	57.0	57.3	57.3	57.0	56.8	56.d
	Coal RNSPS	58.5	58.4	58.7	58.6	58.3	58.0	57.8	57.3	56.9	56.5
	Total Coal	55.8	56.5	57.2	57.7	58.0	58.3	58.5	58.6	58.9	59.2
	Oil/Gas	18.8	18.8	18.8	18.8	18.9	19.1	19.2	19.5	19.8	20.2
	Nuclear	65.8	65.9	65.9	65.8	65.7	65.5	65.3	65.3	65.1	64.8
	Hydro/Other	34.8	34.8	34.8	34.8	34.8	34.7	34.7	34.6	34.5	34.3
	Total East	46.2	46.6	47.0	47.3	47.7	48.1	48.4	48.8	49.2	49.6
West	Coal										
	Coal SIP	44.4	44.8	45.5	46.6	47.7	48.6	49.7	50.7	51.7	52.8
	Coal NSPS	51.8	53.1	54.4	55.7	56.9	57.6	58.2	58.6	58.9	59.2
	Coal RNSPS	61.4	61.7	62.4	63.1	63.6	63.9	64.2	64.4	64.5	64.7
	Total Coal	53.8	54.6	55.7	56.8	57.8	58.4	59.1	59.6	60.1	60.6
	Oil/Gas	23.9	24.1	24.2	24.3	24.4	24.4	24.3	24.4	24.5	24.7
	Nuclear	58.9	59.8	60.8	61.7	62.5	62.8	63.0	62.7	62.0	61.1
	Hydro/Other	54.4	54.4	54.5	54.6	54.6	54.7	54.7	54.7	54.8	54.8
	Total West	43.5	44.0	44.6	45.1	45.7	46.1	46.5	47.0	47.5	48.1
U.S.	Coal										
	Coal SIP	54.1	54.9	55.6	56.4	57.0	57.6	58.3	59.2	60.3	61.7
	Coal NSPS	53.6	54.4	55.4	56.3	57.0	57.4	57.7	57.6	57.6	57.8
	Coal RNSPS	59.7	59.7	60.1	60.2	60.0	459.8	59.7	59.2	58.8	58.4
	Total Coal	55.3	56.0	56.8	57.5	57.9	58.3	58.7	58.9	59.1	59.5
	Oil/Gas	20.8	20.8	20.8	20.9	21.0	21.1	21.2	21.3	21.6	21.9
	Nuclear	64.5	64.8	64.9	65.0	65.1	65.0	64.8	64.7	64.4	63.8
	Hydro/Other	48.1	48.1	48.2	48.3	48.3	48.3	48.3	48.3	48.3	48.3
	Total U.S.	45.3	45.8	46.2	46.6	47.1	47.4	47.8	48.2	48.7	49.2

Table 5.8 Capacity Factors (continued)

(Petawatt Hours)

	1985	1990		1995		2000		2010	
	Actual	CEUM	AUSM	CEUM	AUSM	CEUM	AUSM	CEUM	AUSM
Utility Generation	2.46	2.66	2.64	2.95	2.88	3.21	3.15	3.93	3.81
Cogeneration	0.03	0.08	0.08	0.12	0.12	0.15	0.15	0.19	0.19
U.S. Generation	2.49	2.74	2.72	3.06	3.00	3.37	3.30	4.12	4.01
Canadian Imports	0.04	0.07	0.07	0.06	0.06	0.08	0.08	0.08	0.08
Total Generation	2.53	2.81	2.79	3.13	3.06	3.44	3.38	4.19	4.08
T&D Losses (1)	0.23	0.25	0.23	0.27	0.20	0.29	0.22	0.35	0.24
Electricity Sales	2.30	2.56	2.56	2.86	2.86	3.16	3.16	3.85	3.85
% T&D Losses (1)	9.2	8.8	8.2	8.6	6.7	8.3	6.4	8.3	5.8

(1) Transmission and Distribution Losses

Table 5.9 Electricity Generation, Losses and Sales

(Petawatt Hours)

	1985	1990		1995		2000		2010	
	Actual	CEUM	AUSM	CEUM	AUSM	CEUM	AUSM	CEUM	AUSM
Nuclear Generation	0.3	0.61	0.58	0.63	0.61	0.62	0.62	0.46	0.38
Hydro & Other Utility Generation	0.29	0.34	0.29	0.36	0.31	0.37	0.32	0.38	0.32
Non-fossil Generation	0.68	0.95	0.87	0.99	0.92	0.99	0.94	0.84	0.70
Coal Generation	1.40	1.50	1.32	1.58	1.52	1.78	1.77	2.79	2.67
Oil/Gas Generation	0.39	0.22	0.44	0.38	0.44	0.44	0.45	0.29	0.44
Fossil Generation	1.79	1.71	1.77	1.96	1.96	2.22	2.21	3.09	3.11
Total Generation	2.46	2.66	2.64	2.95	2.88	3.21	3.15	3.93	3.81

Table 5.10 Generation by Plant Type

	1985	1990		1995		2000		2010	
	Actual	CEUM	AUSM	CEUM	AUSM	CEUM	AUSM	CEUM	AUSM
CAPACITY (GW)									
Coal Capacity	287	296	309	301	339	325	369	518	512
Oil/Gas Capacity	205	203	202	204	232	213	247	215	228
Total Fossil Capacity	492	499	511	505	571	538	616	733	740
Nuclear Capacity	76	103	105	106	109	106	110	78	69
CAPACITY FACTORS (%)									
Coal Generation	55.8	57.6	48.9	60.1	51.3	62.4	54.6	61.6	59.5
Oil/Gas Generation	21.5	12.1	24.9	21.1	21.3	23.5	20.7	15.4	21.9
Nuclear Capacity Factors	56.4	67.0	63.3	67.0	64.5	67.0	64.3	67.0	63.8

Table 5.11 Capacity and Capacity Factor by Plant Type

(Quadrillion Btu)

	1985	1990		1995		2000		2010	
	Actual	CEUM	AUSM	CEUM	AUSM	CEUM	AUSM	CEUM	AUSM
Coal	14.58	15.80	13.91	16.79	16.03	18.84	18.63	28.96	27.51
Oil and Gas	4.19	2.51	4.89	4.22	4.84	4.87	5.01	3.57	4.87
Oil	0.99	1.26	2.20	1.79	1.83	2.26	1.77	2.13	1.42
Gas	3.20	1.25	2.69	2.43	3.01	2.61	3.24	1.44	3.45

Table 5.12 Coal, Oil, and Gas Fuel Use

	1985 Actual	1986 Actual	1990		1995		2000		2010	
			CEUM	ADSM	CEUM	ADSM	CEUM	ADSM	CEUM	ADSM
Generation (PWh)										
SIP Coal	0.95	0.93	1.00	0.83	1.03	0.85	1.08	0.90	1.10	0.99
NSPS Coal	0.42	0.42	0.45	0.37	0.50	0.39	0.53	0.42	0.52	0.47
RNSPS Coal	0.03	0.04	0.05	0.12	0.05	0.28	0.17	0.44	1.17	1.21
Total Coal	1.40	1.39	1.50	1.32	1.58	1.52	1.78	1.77	2.79	2.67
Capacity (GW)										
SIP Coal	198	198	199	195	199	194	199	194	194	184
NSPS Coal	84	86	88	88	91	90	94	92	94	92
RNSPS Coal	5	8	10	26	11	54	33	84	231	236
Total Coal	287	292	296	309	301	339	325	369	518	512
Capacity Factors (%)										
SIP Coal	55.0	53.8	57.0	48.8	59.4	50.1	62.1	53.3	65.1	61.7
NSPS Coal	57.4	55.2	59.1	48.5	61.6	49.7	63.5	52.8	63.6	57.8
RNSPS Coal	63.1	51.1	58.2	51.4	60.3	58.4	61.3	59.6	57.8	58.4
Total Coal	55.8	54.2	57.6	48.9	60.1	51.3	62.4	54.6	61.6	59.5

Table 5.13 Coal-Fired Units Generation, Capacity and Capacity Factor by Regulatory Category

(Million Tons of SO_2)

	1980 Actual	1985 Actual	1990		1995		2000		2010	
			CEUM	ADSM	CEUM	ADSM	CEUM	ADSM	CEUM	ADSM
SIP Coal	15.18	13.55	14.73	13.41	15.04	13.77	15.61	14.56	16.47	16.03
NSPS Coal	0.84	2.08	2.08	1.72	2.31	1.84	2.45	2.02	2.47	2.27
RNSPS Coal	—	0.06	0.09	0.26	0.10	0.64	0.27	1.03	1.85	2.94
Total Coal	16.02	15.69	16.90	15.39	17.46	16.25	18.33	17.62	20.79	21.24
Oil/Gas	1.36	0.58	0.89	1.25	1.14	1.03	1.32	0.97	0.93	0.74
Total	17.38	16.27	17.79	16.63	18.60	17.28	19.65	18.59	21.72	21.58

Table 5.14 Coal- and Oil/Gas-Fired Units SO_2 Emissions by Regulatory Category

(Pounds of SO_2 per Million Btu)

	1980 Actual	1985 Actual	1990 CEUM	1990 AUSM	1995 CEUM	1995 AUSM	2000 CEUM	2000 AUSM	2010 CEUM	2010 AUSM
SIP Coal	3.03	2.77	2.83	3.03	2.78	3.02	2.75	3.00	2.84	3.00
NSPS Coal	0.80	0.93	0.83	0.88	0.83	0.90	0.83	0.90	0.86	0.89
RNSPS Coal	—	0.40	0.43	0.43	0.42	0.46	0.34	0.47	0.32	0.48
Total Coal SO_2 Emissions	2.64	2.15	2.14	2.21	2.08	2.03	1.95	1.89	1.44	1.53
Oil/Gas	0.45	0.28	0.79	0.51	0.58	0.43	0.58	0.39	0.60	0.30
Total SO_2 Emissions	1.91	1.73	1.97	1.77	1.79	1.67	1.68	1.57	1.35	1.34

Table 5.15 Coal- and Oil/Gas-Fired Units Average SO_2 Emissions Rate by Regulatory Category

reference 14. In these years, the AUSM and CEUM models are substantially, but not entirely in agreement on the electric generation shares (Figure 5.3). NO_x emissions were not affected. The differences in the SO_2 emissions between coal and gas/oil combustion are more significant. Differences in SO_2 emission estimates are traceable to several differences in the models' respective choices of generating technologies and fuels to meet electric demand. A comparison of the choices made by each model is shown in Figures 5.3 and 5.4. Although total fossil/nonfossil generation is similar in each model (Figure 5.3), the AUSM model selected more gas/oil and less coal-fired generation than did CEUM (Figure 5.4). Results extracted from Tables 5.9 through 5.15 can be used to illustrate that these differences in generation between the models fully account for the small, remaining differences in SO_2 emissions. By adjusting the CEUM generation to the AUSM levels and recalculating the emissions, the adjusted CEUM emissions and the reported AUSM emissions are virtually identical for the years 1990 and 1995. The methodology used to adjust the CEUM emissions to AUSM generation levels and their comparison with the AUSM SO_2 emissions output are given in APPENDIX D. In the year 2000 the generation differences between CEUM and AUSM for coal, oil, and gas are minor as is shown by Figure 5.4. Other factors are affecting the respective projections for the years 2000 and 2010. Between 2000 and 2010, there is widening disagreement between AUSM and CEUM relative to dispatching and choices of fuels for coal-fired steam generating capacity subject to the 1979 revisions of the New Source Performance Standards (RNSPS).

RNSPS units are not only dispatched more in the AUSM model, but have higher average emission rates (indicating use of higher sulfur coals than in CEUM) and higher total emissions (see Tables 5.13 through 5.15). This resulted in lower total coal-fired emissions from AUSM, relative to CEUM, for these years since existing coal-fired units subject to higher emissions standards [i.e., State Implementation Plans (SIP's)] were, as a consequence of higher RNSPS capacity utilization, dispatched less than in CEUM (see Table 5.13).

Figure 5.1 Comparison of AUSM and CEUM Emissions Projections

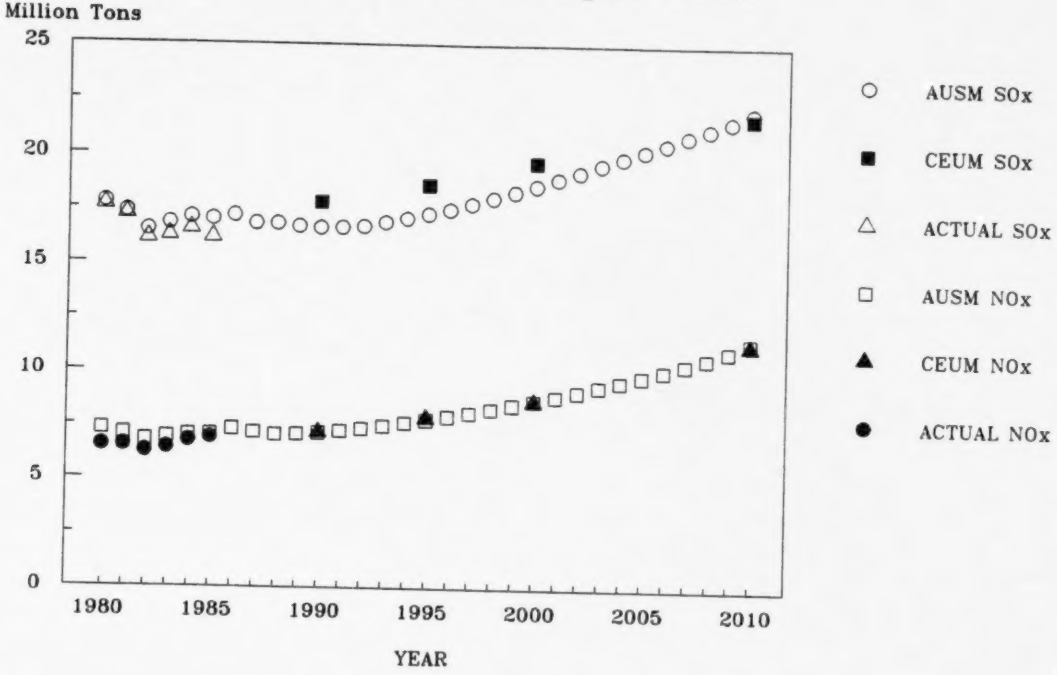


Figure 5.2 AUSM and CEUM Projections Comparison

Generation From All Sources, PWh

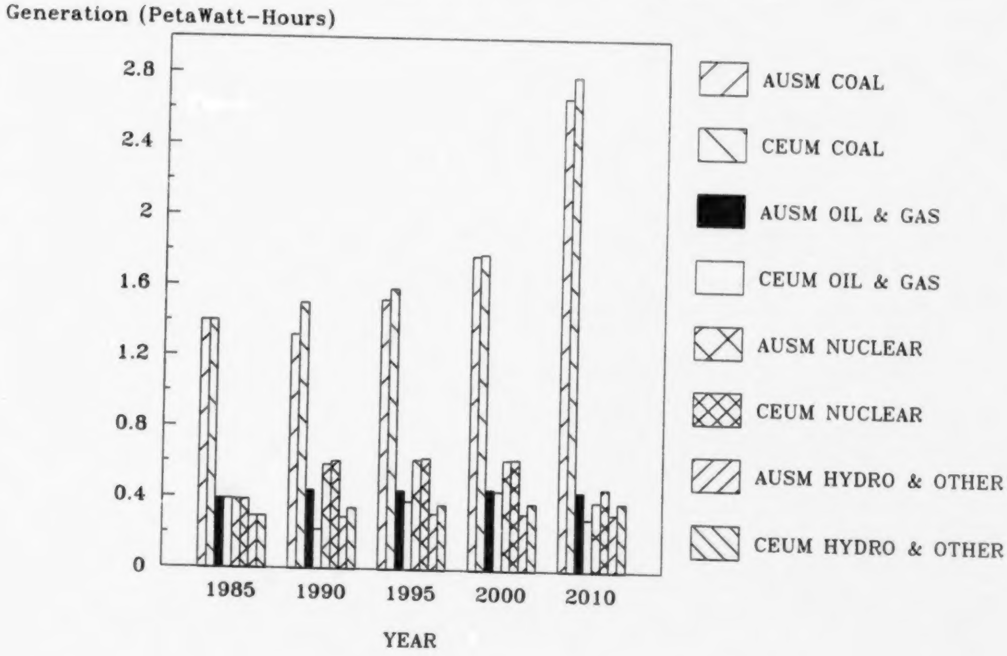


Figure 5.3 AUSM & CEUM Projections Comparison
Fossil – Nonfossil Generation

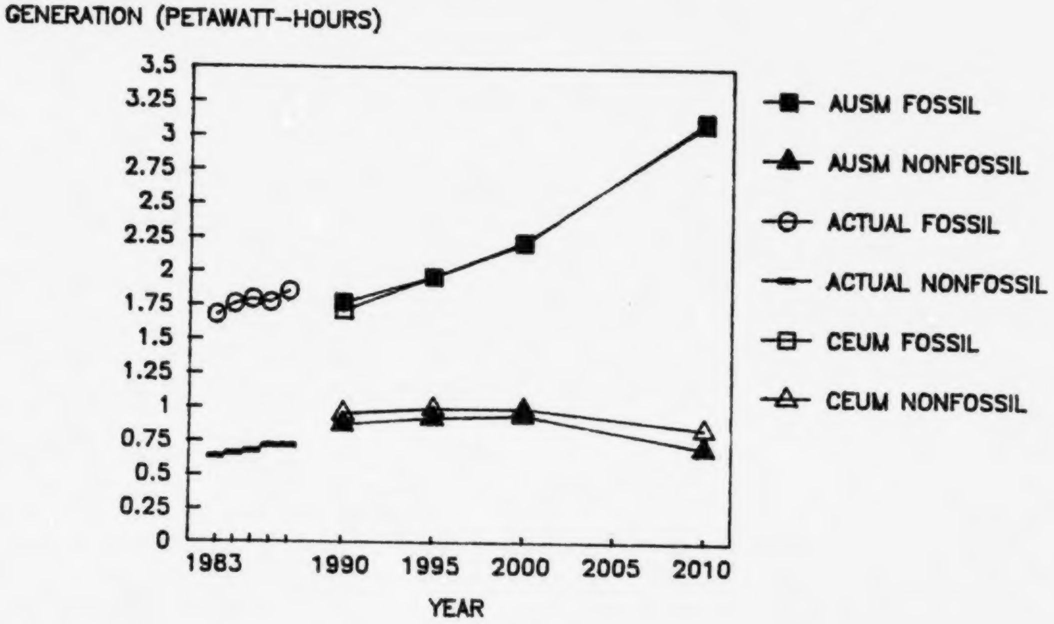
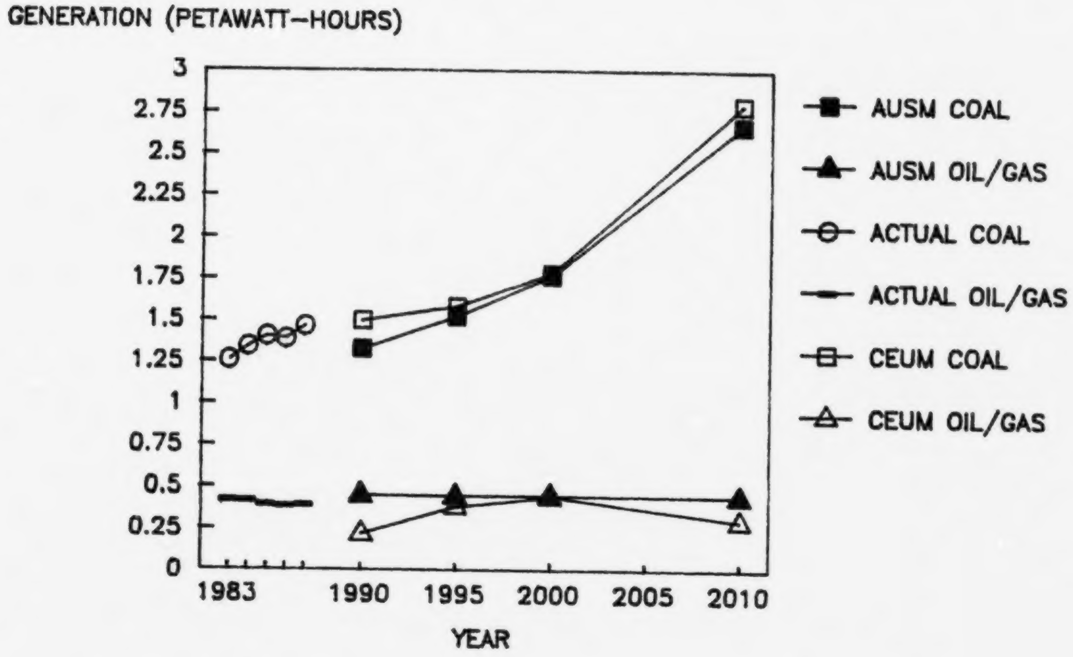


Figure 5.4 AUSM & CEUM Projections Comparison
Coal, Oil & Gas Fossil–Fuel–Fired Units



Another factor that has significant influence on the forecasts relates to the differences in input assumptions for AUSM and CEUM. Constraints in CEUM act to produce increasing proportions of transmission and distribution losses over time. AUSM actually shows losses declining as new capacity is located closer to load centers within a state. These assumptions produce lower generation in AUSM over time with the maximum difference between AUSM and CEUM occurring in the year 2010 when total utility generation is 0.12 PWh lower in AUSM; a difference in total generation fully accounted for by the lower transmission losses in AUSM (Table 5.9).

Even though CEUM generated an additional 0.12 PWh (3.93 PWh from CEUM less 3.81 PWh from AUSM), additional emissions were not projected by CEUM relative to AUSM due to higher generation by non-fossil sources in CEUM. Table 5.10 shows that CEUM produced an additional 0.13 PWh of non-fossil generation (0.840 PWh from CEUM less 0.706 PWh from AUSM) in its base case projection relative to the AUSM model. This difference is in part due to higher projections of hydroelectric generation by CEUM relative to AUSM.

It is evident from the "backcasting" and forecasting test runs that Version 3.0 of the AUSM model does produce forecasts closely in agreement with historic emissions and substantially in agreement with the CEUM model projections when the same inputs are used. Based on these and other results published in this report and results of testing the many modifications made to the AUSM described in other reports in this series, Version 3.0 of AUSM is ready for use in analyses by the modeling community, and is being released on magnetic tape to the public through the National Technical Information Service, Springfield, Virginia [12].

Future program activities will focus on gaining an improved understanding of the basis for the AUSM model outputs and refinement of AUSM data bases. Current 1980 vintage unit inventory data in AUSM, Version 3.0 will be replaced with updated 1985 unit inventory data when Version 4.0 of AUSM is released. Other improvements that will be incorporated in Version 4.0 include a national loop Multi-Period, Multi-State Module expansion from 10 to 20 technology categories, and an expansion of the forecast horizon from the year 2009 to 2030.

6 1980 NURF Inventory vs AUSM SO_2 EMISSIONS

IMPACTS, the state-level model module used to calculate emissions, was evaluated to determine whether it is receiving information from the unit inventory (file E5) accurately and to compare calculated SO_2 emissions with SO_2 emission rates tabulated in the inventory. It was found that data is accurately passed to the module and that calculated emissions agree with tabulated emissions within reasonable tolerances. Calculation errors are less than 1 percent for seven of the top ten emitting states, between 3 and 6 percent for three of the top ten states and less than 1 percent nationally (see Table 6.1).

This study was undertaken to develop an understanding of AUSM's accuracy and reliability as a tool for calculating emissions. It is clear from the results of this study that this is true and that SO_2 emissions forecasts are accurate to the extent that backcast experiments yield acceptable results.

6.1 Introduction

The 1980 NURF Inventory is derived largely from three sources: FPC Form 423, EIA Form 759, and the EPA Flue Gas Desulfurization Survey. SO_2 emissions, the major concern of this study, are not directly reported in these sources. SO_2 emissions are calculated based on fuel quantity, fuel quality, plant operation, and control technology attributes that are collected by DOE and EPA. The data sources supporting the 1980 NURF Inventory and the AUSM unit inventory contain the majority of fuel and plant attributes employed in the emissions calculations.

Although the original data sources are known to be the same, two major differences exist between the 1980 NURF Inventory and the AUSM unit inventory. First, there are slight differences in assumptions and methods used to derive emissions factors. In particular, these differences include treatment of SO_2 removal in FGD systems and sulfur retention in the ash. Second, 1980 NURF Inventory SO_2 emission estimates are derived using a plant level analysis while AUSM is supported by unit level inventory data.

6.2 Comparison Methods

An algorithm was developed to recalculate 1980 SO_2 emissions for generating units in the AUSM. It employs data elements consistent with the 1980 NURF Inventory, with the exception of emissions factors which are derived within AUSM. The 1980 emissions resulting from this exercise were compared to the 1980 NURF Inventory for each of the top ten emitting states and for the aggregate group of ten states. This analysis quantifies the deviation in AUSM emissions relative to the 1980 NURF Inventory for a scenario where AUSM capacity factors are in complete agreement with the utilization levels reported in the 1980 NURF Inventory.

6.2.1 Objectives

The first objective of this study is to verify that AUSM is receiving, in the correct form, unit inventory information needed to calculate the SO_2 emission factors. Specifically, this information includes fuel sulfur and heat content, plant heat rate, and control technology identification codes and removal levels. The second objective is to quantify the differences in state-level SO_2 emissions that are attributable to differences in the methods used in calculating emissions factors in the 1980 NURF Inventory and the AUSM.

6.2.2 Procedures

The following procedures were followed:

1. Extract 1980 emissions factors and the information used to calculate them for each individual generating unit.
2. Compare the extracted information to the corresponding data in the AUSM unit inventory data file.
3. Calculate the unit level SO_2 emissions using the extracted data in step 1 and 1980 NURF Inventory utilization levels.
4. Aggregate the SO_2 emissions calculated in step 3 to a state level and compare to the corresponding emissions in the 1980 NURF Inventory.

The Impacts module of the AUSM state-level model was modified to produce an output file containing 1980 emissions factors for individual generating units. Also included in the file is the information used to calculate the emissions factor for each unit. This modified code was used in a one year state-level model run for the top ten emitting states. The data taken from the AUSM unit inventory was cross checked with the inventory data in the Impacts module trace file. Lotus 1-2-3 was used to calculate 1980 SO_2 emissions for each unit using Equation 1. (Because 1980 was a leap year, a value of 8784 is employed for the number of hours in the year.) The results were aggregated to the state-level and then compared to the 1980 NURF Inventory SO_2 emissions.

$$\text{Emissions} = \text{Unit Size} \times \text{Capacity Factor} \times \text{Emissions Factor} \times 8784 \qquad (1)$$

6.3 Input Data

No special input data have been employed in this study. Capacity factors used in Equation 1 correspond directly to the utilization levels identified in the

1980 NURF Inventory. The November 1986 AUSM unit inventory is the primary source for all generating unit information. Data sources for the 1980 NURF Inventory are documented in Pechan 1984 and Pechan 1985.

6.4 Results

A comparison of data in the AUSM unit inventory and data in the Impacts trace file indicates that data elements employed by the state model within AUSM to calculate SO_2 emissions are being correctly received by the model. These processed data elements match the corresponding data in the unit inventory in each case for every unit in the top ten emitting states.

Table 6.1 compares AUSM and 1980 NURF Inventory estimated SO_2 emissions (equation 1) for the top 10 emitting states. Seven of the ten observations showed differences in emissions of less than 1 percent, with the remaining three states (Kentucky, Pennsylvania, and Florida) showing deviations of 3 to 6 percent. As is evident in Figure 6.1, a majority of the emissions coming from these 10 states have emission differences of less than 5 percent, with none greater than 10 percent. On an aggregate level, emissions differ by less than 0.65 percent.

AUSM Inventory vs. 1980 NURF Inventory (1000 tons)

State	1980 NURF Emissions Inventory	1980 AUSM Emissions Inventory	Percent Difference
Ohio	2207	2224	0.68%
Indiana	1580	1575	-0.32%
Pennsylvania	1504	1438	-4.64%
Missouri	1175	1183	0.68%
Illinois	1145	1142	-0.35%
Kentucky	1048	993	-5.25%
W. Virginia	968	972	0.41%
Tennessee	959	960	0.10%
Georgia	758	758	-0.13%
Florida	720	743	2.91%
Total	12063	11988	-0.62%

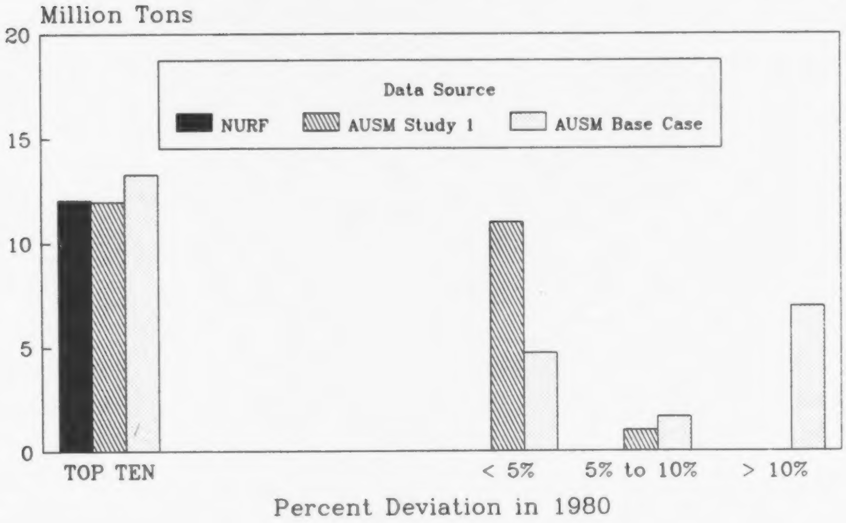
Table 6.1 Comparison of 1980 SO_2 Emission Estimates

6.5 Conclusions

After correcting for capacity factors, the only identifiable differences between the two sets of emissions reported in Table 6.1 are the method used to calculate SO_2 emissions factors and the level of aggregation of the data (plant vs. unit level). This study demonstrates that these differences can cause AUSM and 1980 NURF Inventory emissions estimates to deviate from one another for some states. Even so, at an aggregate level the differences are insignificant relative to total emissions for the top ten emitting states.

This level of improvement can be attributed to employing capacity factors consistent with those used by the 1980 NURF Inventory. Presently, AUSM only requires a technology category to maintain an average generating level, thus allowing unit utilization levels to range from 0 to the maximum availability limit as long as this average is met. Although using actual utilization levels would be ideal, they only exist for historical years and it would not be

Figure 6.1 1980 SO2 Emissions
Calibration Study: AUSM & NURF
Top 10 Emitting States



realistic to require units to maintain these levels throughout the simulation. A more realistic recommendation is to put a lower bound on the unit level capacity factor constraint to approximate a unit's turndown ratio. The study in Chapter 10 emerged as a result of this realization.

7 CALIBRATION OF 1980 INTERSTATE POWER TRANSFERS

The objectives of the calibration study were to analyze differences between simulated and historical emissions associated with interstate electricity transfers and to find ways of calibrating emissions levels to historical transfer levels. The Multi-Period, Multi-State (MPMS) module of the AUSM simulates power transfers in order to minimize the total cost of meeting regional demand while honoring constraints. It was found that emissions forecasts for historical years improve significantly by using historical transfers.

7.1 Introduction

State SO_2 emissions are affected by the generating level within that state. If the transfer levels required by that state are inaccurately estimated, generation levels will be incorrectly stated and SO_2 emissions will be directly affected. The National Loop of the AUSM (specifically, MPMS) typically supplies the state-level power model with state transfer data. Because the MPMS transfers are a result of a least cost optimization, the slate of power transfers derived from MPMS may result in a higher level of emissions in 1980 than that which actually occurred. In reality, each power pool is not dispatched perfectly in a least cost manner, and plants with high emissions rates tend to have lower variable costs. As a result, the AUSM generation level in some states may be significantly different than actual generation reported for 1980. Additionally, MPMS power transfers represent only intra-regional transfers, while the 1980 regional energy balance (presented in Table 7.1) indicates the presence of interregional transfers. This study was developed to investigate the influence of interstate power transfers on AUSM SO_2 emissions estimates.

	Generation		Sales	Net Exports		
Power Pool		Plus Imports		Plus Trans. & Distribution Losses	Assuming 11% Losses	Percent of Regional Sales
NEPOOL	78200	84455	77218	7237	-1256.98	-1.63
NYPOOL	108600	129992	105927	24065	12413.03	11.72
MIDATL	190800	190800	197212	-6412	-2340.32	-1.19
VIRCAR	148200	148200	148830	-630	-17001.30	-11.42
TVASOU	220300	220300	199381	20919	-1012.91	-0.51
FLORID	95900	95900	90596	5304	-4661.56	-5.15
ESTCEN	383600	384383	310486	73897	12334.54	3.97
WISILL	141300	141300	133559	7741	-6950.49	-5.20
MIDAPP	94100	99875	82530	17345	8266.70	10.02
SOUCEN	184100	184100	175998	8102	-11257.78	-6.40
ERCOTX	203000	203000	177945	25055	5481.05	3.08
NOWEST	212000	212000	177085	34915	15435.65	8.72
SOWEST	216000	223958	209446	14512	-8527.06	-4.07
Nation	2276100	2318263	2086213	232050	2566.57	0.12

Table 7.1 Power Pool Electricity Balance for 1980

7.2 Approach

Interstate power transfer levels have been identified as possibly contributing to the differences observed between the AUSM and the 1980 NURF Inventory SO_2 emissions estimates. Therefore, the 1980 transfer data provided by MPMS are exogenously replaced with estimates of actual 1980 transfers. This is done for the top ten emitting states only because data entry requirements are extensive.

State	FIPS	Net 1980 Exports (gigawatt hours)		FIPS	Net 1980 Exports (gigawatt hours)
ALABAMA	1	20,680	NEBRASKA	31	588
ARIZONA	4	7,824	NEVADA	32	3,638
ARKANSAS	5	-5,879	NEW HAMPSHIRE	33	-756
CALIFORNIA	6	-42,243	NEW JERSEY	34	-25,908
COLORADO	8	107	NEW MEXICO	35	14,318
CONNECTICUT	9	1,020	NEW YORK	36	-8,980
DELAWARE	10	279	NORTH CAROLINA	37	2,339
FLORIDA	12	-4,661	NORTH DAKOTA	38	10,040
GEORGIA	13	5,913	OHIO	39	-16,416
IDAHO	16	-7,568	OKLAHOMA	40	10,121
ILLINOIS	17	-3,651	OREGON	41	-5,551
INDIANA	18	8,578	PENNSYLVANIA	42	11,760
IOWA	19	-5,882	RHODE ISLAND	44	-4,676
KANSAS	20	603	SOUTH CAROLINA	45	-92
KENTUCKY	21	-279	SOUTH DAKOTA	46	3,261
LOUISIANA	22	-20,244	TENNESSEE	47	-19,768
MAINE	23	-931	TEXAS	48	5,472
MARYLAND	24	-13,565	UTAH	49	12
MASSACHUSETTS	25	-1,861	VERMONT	50	-305
MICHIGAN	26	-561	VIRGINIA	51	-19,215
MINNESOTA	27	-5,511	WASHINGTON	53	9,984
MISSISSIPPI	28	-7,815	WEST VIRGINIA	54	47,645
MISSOURI	29	4,156	WISCONSIN	55	-3,351
MONTANA	30	3,552	WYOMING	56	14,897
		TOTAL	-38,879		

Table 7.2 State Power Exports for 1980

By calibrating 1980 transfer levels, it is anticipated that total generation within a state will match the reported level of generation. However, as in other AUSM runs, there is no assurance that generation at the unit level or generation by type of fuel will approximate reported values for 1980.

7.2.1 Objectives

The objective of this study is to provide accurate simulations of 1980 SO_2 emissions for the top ten emitting states by improving the accuracy of interstate power transfer data. At the same time, the error in 1980 SO_2 emissions associated with using interstate power transfer levels provided by MPMS as opposed to those derived from a state energy balance employing 1980 sales and generation data will be quantified.

7.2.2 Procedures

A four step procedure has been developed to meet the stated objectives.

1. Estimate actual 1980 interstate power transfers.
2. Replace the transfer data provided by the National Loop (MPMS) with those estimated in step 1.
3. Execute the state-level model.
4. Compare new SO_2 emissions estimates with those derived from the 1980 NURF inventory and the AUSM Base case.

Estimates of 1980 interstate power transfers were derived by conducting an electricity generation and sales balance for each of the top ten SO_2 emitting state. These new estimates were put into the E9 data file [10] to replace the 1980 interstate power transfer data provided by MPMS during the AUSM Base case run. The state-level model was then executed for each of these states. AUSM state-level generation and emissions values for 1980 were compared to the 1980 NURF Inventory and the AUSM Base case results.

Gigawatt Hours per Year

State	1980 Generation	1980 Exports	MPMS 1980 Exports
Ohio	110,243	-16,415	-20,897
Indiana	70,618	8,578	2,894
Pennsylvania	122,511	11,760	21,404
Missouri	48,928	-7,815	17,046
Illinois	103,416	-3,651	0
Kentucky	57,104	-279	-1,189
W. Virginia	70,795	48,590	47,644
Tennessee	60,214	-19,768	-11,504
Georgia	63,312	5,912	-18,792
Florida	95,901	-4,660	0
Net Total		16,931	36,606

Table 7.3 Comparison of 1980 Interstate Power Transfer Levels

7.3 Input Data

Data requirements are limited to 1980 interstate power transfers. Since little data for historical state level power transfers are available, these values have been derived. The methodology used to derive these values is as follows:

1. Compute estimates of transmission and distribution losses from a national electricity balance.

2. Compute state sales information from a state-level electricity balance.

3. Derive state power purchases by applying the loss factor to each state's sales data.

Transmission and distribution (T&D) losses are not available for most states. Therefore, an average loss factor has been estimated for 1980 by using the national-level electricity balance identified in Equation 2 [10].

$$\text{NATIONAL T\&D LOSSES} = \frac{\text{GENERATION}_{80} + \text{NET IMPORTS} - \text{SALES}_{80}}{\text{SALES}_{80}} \qquad (2)$$

The resulting average transmission and distribution loss factor is 11 percent for the nation. AUSM applies the 11 percent average loss factor to each state's sales data to determine the total amount of energy the state utility must supply to the state grid. The model will meet this requirement via in-state generation or interstate power purchases.

An electricity balance has been generated for each of the top ten emitting states to estimate net inflows or outflows of electricity for each state. Distribution losses and sales are subtracted from 1980 generation to obtain a value for total exports. This calculation is shown in Equation 3.

$$\text{NET STATE EXPORTS}_{80} = \text{GENERATION}_{80} - (1.11 * \text{SALES}_{80}) \qquad (3)$$

The interstate power transfers derived from Equation 3 are listed by state in Table 7.2. Table 7.3 presents a comparison of Base case transfer levels for 1980 verses calculated values for the top ten emitting states.

7.4 Results

By using actual 1980 interstate power transfers instead of those modeled by the national loop, the accuracy of 1980 SO_2 emissions improves for eight of the top ten largest emitting states, as well as for the aggregate group. Table 7.4 compares the new SO_2 emissions levels with the 1980 NURF Inventory values for these ten states, and Figure 7.1 presents the improvement in emission estimates relative to the AUSM Base case. As is evident, those states whose

AUSM Transfer Study Results vs. NURF Inventory

AUSM Emissions Performance Relative to NURF Inventory	State/ Region	Emissions AUSM	NURF
		(1000 tons of SO_2)	
AUSM < -10% of NURF	None		
-10% <= AUSM < -5%	Georgia	716	758
-5% <= AUSM < 0%	None		
0% <= AUSM < 5%	Missouri	1177	1175
	Ohio	2252	2207
	W. Virginia	983	968
5% <= AUSM < 10%	Top Ten	12887	12063
	Indiana	1715	1580
	Pennsylvania	1571	1504
	Tennessee	1041	959
AUSM > 10% of NURF	Illinois	1351	1145
	Kentucky	1232	1048
	Florida	849	720

Table 7.4 SO_2 Emissions for the Top Ten Emitting States in 1980

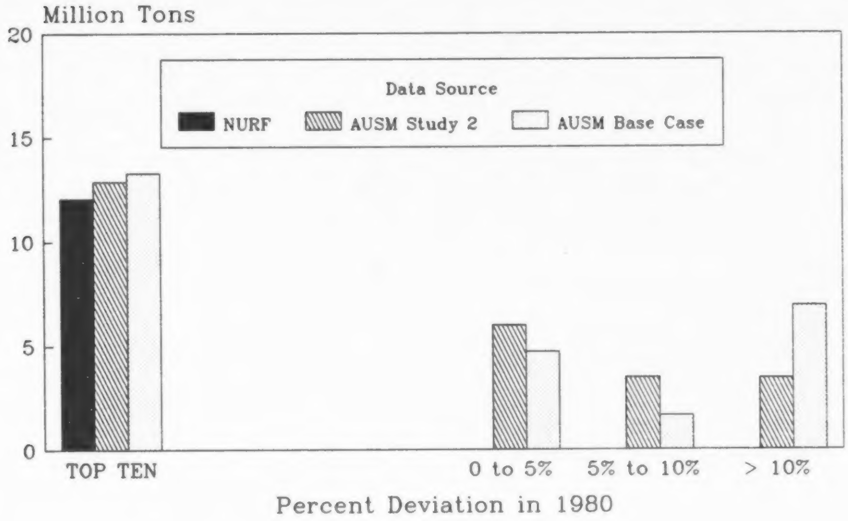
emissions levels differed from the 1980 NURF Inventory by more than 10 percent represent a smaller portion of total emissions as compared to the Base case. Likewise, those states whose emissions levels are within 5 percent of the 1980 NURF Inventory represent a larger portion of total emissions as compared to the Base case. The emissions estimate for the group of ten states is within 6.7 percent of the 1980 NURF Inventory emissions value for these states. This result indicates that one third of the error associated with estimating 1980 SO_2 emissions is attributable to an inaccurate estimate of 1980 transfer levels in MPMS.

Three of the six top ten states which previously violated the +/-10 percent evaluation criteria were brought in the acceptable range as a result of correcting the interstate transfer levels. The states that showed a vast improvement are also the states that had the greatest error in the power transfer levels generated by MPMS. The three states which did not show improvement are Illinois, Kentucky, and Florida. Although the 1980 MPMS transfer levels for these three states may be in error, the error has a small impact on total state generation. This error is typically on the order of 2 to minus 5 percent of total generation. It is not surprising that correction of these transfer levels have little impact on the AUSM forecast of 1980 emissions.

7.5 Conclusions

Two conclusions are drawn from this AUSM study. First, inaccurate estimates of interstate power transfers within the national loop contribute significantly to the errors in calibrating 1980 SO_2 emissions. Thus it is important that AUSM have access to and be given the best available estimate of historical interstate transfers. Second, even though accuracy in state level generation can be achieved in AUSM, accurate emissions forecasts may not follow. The next chapter investigates the first issue for the remainder of the 1980 through 1985 time period. Chapters 9 and 10 address the second issue in more detail by analyzing the distribution of generation by fuel type and unit level capacity factors for coal plants.

Figure 7.1 1980 SO2 Emissions
Calibration Study: AUSM & NURF
Top 10 Emitting States



8 CALIBRATION OF HISTORIC GENERATION LEVELS

The objective of this part of the calibration study was to improve SO_2 emission forecasts for historical years by determining ways of calibrating simulated to actual generation. Significant improvements were achieved by modifying AUSM to use historical demand and interstate transfer values rather than simulated demands and transfers, as intended by the original designers of AUSM. Importantly, use of historic values results in improvement without recourse of scaling or other ad hoc techniques.

8.1 Introduction

As a follow-on to the study in Chapter 7, this study explores how the use of historical demand growth rates and interstate power transfer data can improve the accuracy of forecasting SO_2 emissions for the remaining historical years in the AUSM simulation -- 1981 to 1985. Because this study required an extensive data development effort and some coding modifications, it was conducted only after the study in Chapter 7 proved successful in improving 1980 SO_2 emissions forecasts.

8.2 Experimental Description

Historical state-level electricity sales and interstate power transfer data are employed by AUSM in an effort to replicate SO_2 emissions for each year from 1981 through 1985. This requires modifying the model to accept twenty growth rate periods as opposed to five and employing annual interstate power transfer data. (Twenty growth rate periods were deemed to be adequate because if ten annual rates were required for the 1980 to 1990 period, the additional ten slots would be needed to provide a sufficient level of resolution to define outyear growth rates.)

8.2.1 Objectives

The objective of this study is to more accurately replicate SO_2 emissions for 1981 through 1985 by improving the accuracy of interstate transfer data and demand levels during this time period. The resulting improvement in SO_2 emissions forecasting capability for AUSM will be quantified.

8.2.2 Procedures

The stated objective was met using the following five step procedure.

1. Develop growth rate and power transfer data.
2. Develop driver file data.
3. Modify state model.
4. Execute state model for the nation.
5. Analyze state and national emissions trends.

Data and driver file development efforts are discussed in section 8.3 Input Data. Model development efforts focus on 1) expansion of the data group that contains the sales growth rates and 2) implementation of a scenario option to employ historical transfer levels for the 1980 to 1985 time period while switching to AUSM national loop transfer levels for future years. The AUSM state-level model is executed in a routine fashion and analysis of the output is conducted by comparing AUSM emission levels to the 1980 NURF Inventory.

8.3 Input Data

Demand growth rates and interstate power transfer data are estimated from state sales and generation data and international power transfer data. Information on electricity sales and generation published by the Edison Electric Institute [references 15 through 20] is obtained from Energy Information Agency surveys. International power transfer data also are obtained from this source [21].

	FIPS State		Years				
Region/State	**Code**	**Type**	**1981**	**1982**	**1983**	**1984**	**1985**
NEPOOL							
Connecticut	9	1	-4.0%	2.9%	-2.3%	14.6%	-7.3%
Maine	23	1	15.6%	-9.1%	15.2%	-4.4%	-0.8%
Massachusetts	25	1	-5.3%	3.1%	2.1%	-4.9%	8.8%
New Hampshire	33	1	-6.2%	-12.6%	9.2%	16.4%	-3.6%
Rhode Island	44	1	-2.6%	-7.1%	2.9%	0.4%	-1.0%
Vermont	50	1	18.3%	9.7%	-20.7%	12.0%	-5.4%
NEWYRK							
New York	36	1	-2.4%	-3.5%	2.8%	3.7%	2.2%
MIDATL							
Delaware	10	1	24.6%	-16.7%	39.2%	-1.1%	-9.5%
Maryland	24	1	-5.2%	-1.5%	7.2%	6.6%	-6.7%
New Jersey	34	1	4.3%	-0.5%	-7.6%	-1.8%	14.8%
Pennsylvania	42	1	-5.5%	2.3%	4.7%	6.9%	3.5%
VIRCAR							
North Carolina	37	1	-1.5%	-10.1%	23.1%	-1.9%	16.4%
South Carolina	45	1	-2.4%	-3.3%	11.7%	10.8%	9.4%
Virginia	51	1	6.0%	-1.5%	2.0%	0.7%	6.2%
TVASOU							
Alabama	1	2	-6.2%	-0.2%	3.1%	1.9%	-8.4%
Georgia	13	2	-2.4%	-7.6%	-0.1%	23.4%	47.7%
Mississippi	28	2	-14.5%	9.9%	-15.3%	9.8%	15.3%
Tennessee	47	2	-1.6%	0.7%	13.7%	-0.8%	-2.6%
FLORID							
Florida	12	2	3.1%	-6.5%	-0.5%	2.7%	1.9%

Table 8.1 Annual Electricity Demand Growth Rates [15,16,17,18,19,20]

Yearly growth rates have been calculated for each state using the annual electricity sales data and are presented in Table 8.1. As is evident, growth rates can fluctuate from one year to the next. Since state-level emissions depend directly on demand levels, failure to include actual annual demand growth rates for historical years may result in inaccurate estimates of emissions.

	FIPS State		Years				
Region/State	Code	Type	1981	1982	1983	1984	1985
MIDAPP							
Iowa	19	1	3.0%	-2.7%	1.4%	1.8%	2.5%
Minnesota	27	1	-0.1%	-7.8%	4.2%	-4.1%	6.5%
Nebraska	31	1	-1.5%	14.0%	-6.6%	5.4%	-11.0%
North Dakota	38	1	4.0%	35.7%	13.8%	21.3%	1.5%
South Dakota	46	1	-12.7%	-0.6%	-2.9%	7.7%	-6.1%
SOUCEN							
Arkansas	5	2	21.0%	-5.8%	23.4%	-0.1%	14.8%
Kansas	20	2	-2.4%	-5.6%	2.5%	10.1%	4.4%
Louisiana	22	2	-2.5%	-4.0%	-7.6%	4.5%	8.2%
Missouri	29	2	-0.3%	0.6%	8.3%	6.5%	2.4%
Oklahoma	40	2	-1.6%	2.4%	2.0%	-1.5%	-2.5%
ERCOTX							
Texas	48	2	2.2%	-0.4%	-0.1%	5.6%	0.2%
NOWEST							
Colorado	8	1	7.3%	0.7%	-1.3%	8.3%	4.4%
Idaho	16	1	-0.0%	11.7%	6.2%	2.0%	-11.0%
Montana	30	1	9.3%	-13.4%	2.3%	36.1%	-0.8%
Oregon	41	1	9.2%	22.7%	-3.0%	5.7%	-6.8%
Utah	49	1	-2.9%	1.1%	4.1%	9.7%	9.9%
Washington	53	1	12.7%	-6.4%	-2.0%	0.1%	-2.3%
Wyoming	56	1	52.3%	8.7%	-8.9%	37.8%	20.7%
SOWEST							
Arizona	4	2	12.9%	-5.2%	8.7%	12.7%	5.8%
California	6	2	-5.8%	-6.7%	-0.4%	2.5%	3.5%
Nevada	35	2	15.6%	-1.1%	14.4%	21.8%	-20.5%
New Mexico	32	2	-15.4%	7.9%	34.3%	-2.1%	1.5%

Table 8.1 Annual Electricity Demand Growth Rates (continued) [15,16,17,18,19,20]

Annual interstate power transfers have been calculated using the methods outlined in Chapter 6. An 8.5 percent (as opposed to the 11 percent used for the study in Chapter 7) transmission and distribution loss coefficient has been employed for this study after discovering that the 11 percent loss factor was based on "preliminary" 1980 sales, generation, and import data. The 8.5 percent loss factor was obtained by performing an electricity balance for each of the historical years using historical sales, generation, and import data, and approximating an average loss factor. The results of the annual electricity balances for 1980 to 1985 are presented in Table 8.2. Use of a single value for the loss coefficient results in a small error (less than 1.1 percent) in the national energy balance. Table 8.3 identifies state-specific transfer values.

8.4 Results

The ability of AUSM to forecast historical SO_2 emissions is substantially improved when the model uses historical data 1) to define annual demand growth rates and 2) to estimate annual power sales and purchases. This can be seen for SO_2 emissions from the top ten emitting states (Figure 8.1) and, to a greater extent, for national SO_2 emissions (Figure 8.2). As a direct result of using historical growth rate and power transfer data, the differences between the AUSM forecast and the 1980 NURF Inventory-based emissions have been reduced by half

Figure 8.1 SO2 Emissions

AUSM Base Case & Transfer Study vs NURF

Top 10 Emitting States: 1980 to 1985

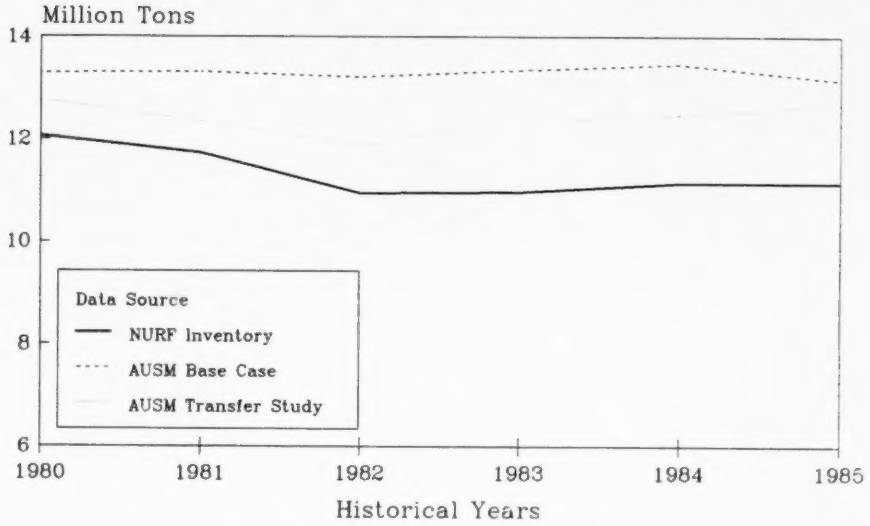
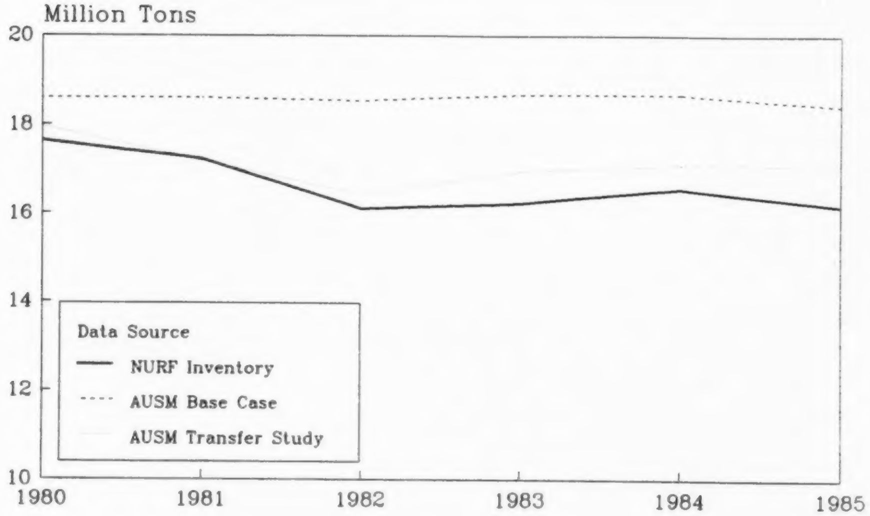


Figure 8.2 SO2 Emissions, U.S.

AUSM Base Case & Transfer Study vs NURF

U.S. Total, 1980 to 1985



for the top ten emitting states and by two-thirds for the nation (Figures 8.1 and 8.2). The results indicate that AUSM's ability to forecast emissions diminishes as the model progresses away from 1980. This increase in error may be attributable to non-modelled inventory issues. For example, the model has no information on fuel switching or scrubber additions that have occurred during this time frame. Methods of incorporating this data and overcoming these modeling limitations are currently being explored.

8.5 Conclusions

As a result of incorporating annual electricity sales growth and power purchase data into the model, the trend in AUSM SO_2 emissions more closely follows the trend observed in the 1980 NURF Inventory for every historical year, 1980 to 1985. Several states' capability to forecast SO_2 emissions is extremely poor despite the fact that total generation by coal and oil technologies is very close to reported values. The poorest emissions forecasting performance during 1980 through 1982 occurs in Kentucky, Illinois, Georgia, and Florida. Some of this error may be attributable to non-modelled changes in the type of coal consumed and the control options employed at various units. These non-modelled changes are not significant enough to cause the magnitude of error observed in many states.

1000 Gigawatt Hours	1980	1981	1982	1983	1984	1985
Sales	2117	2141	2090	2150	2270	2304
Generation	2277	2285	2231	2300	2406	2459
Percent Losses	9.6	8.7	8.2	8.6	7.7	8.5

Table 8.2 Annual National Electric Energy Balance

It is clear that issues other than calibration of demand and power purchases or changes in the unit inventory have a significant impact on AUSM's ability to forecast emissions in these states. These results dictate that analyses should be undertaken to explore utilization of individual coal units which contribute a disproportionate share to a state's total emissions. Studies 4 and 5 (Chapters 9 and 10) have been developed in response to this need.

Millions of Kilowatt Hours Imported

STATE	FIPS	1980	1981	1982	1983	1984	1985
Alabama	1	-21,841	-19,831	-23,456	-25,282	-22,827	-18,379
Arizona	4	-8,145	-8,677	-9,962	-10,981	-12,600	-12,807
Arkansas	5	7,099	410	863	-4,458	-3,132	-9,681
California	6	47,457	63,656	68,197	71,245	80,416	79,728
Colorado	8	514	-987	-1,103	13	-12	-356
Connecticut	9	-1,439	-456	-1,639	-179	-2,181	215
Delaware	10	70	-2,169	-1,108	-2,884	-2,620	-1,597
Florida	12	4,7[illegible]0	4,735	11,191	16,940	17,931	23,929
Georgia	13	-4,283	-1,211	-244	-5,692	-5,040	-8,693
Idaho	16	7,417	8,263	5,484	4,987	4,240	6,806
Illinois	17	2,909	6,199	7,799	5,510	6,521	3,887
Indiana	18	-9,614	-6,457	-3,266	-7,925	-17,679	-15,577
Iowa	19	5,785	4,475	4,858	5,509	4,994	4,256
Kansas	20	-814	-484	1,097	1,467	2,944	1,979
Kentucky	21	819	-4,503	-5,645	-2,777	-253	-6,227
Louisiana	22	19,881	22,148	21,800	22,381	26,945	21,338
Maine	23	757	-409	577	58	1,213	1,526
Maryland	24	12,355	15,402	15,362	14,546	14,248	19,171
Massachusetts	25	1,127	3,051	2,167	3,488	7,584	5,057
Michigan	26	-213	-1,568	1,785	3,120	5,665	4,499
Minnesota	27	5,745	6,219	8,691	8,761	13,171	11,021
Mississippi	28	7,000	10,771	8,175	12,542	12,549	9,487
Missouri	29	-4,640	-5,031	-5,136	-5,876	-8,213	-8,422
Montana	30	-3,726	-4,606	-3,397	-4,167	-6,268	-5,677
Nebraska	31	159	-105	-1,869	-703	-1,052	1,054
Nevada	32	-3,852	-4,679	-4,629	-6,454	-8,655	-4,536
New Hampshire	33	647	1,046	1,881	1,646	1,052	1,667
New Jersey	34	24,614	22,090	21,488	28,018	30,805	24,033
New Mexico	35	-13,898	-11,975	-12,879	-16,203	-14,844	-14,343
New York	36	28,205	30,937	33,350	34,285	33,654	32,355
North Carolina	37	-3,541	-63	-2,227	1,953	-2,001	4,072
North Dakota	38	-4,172	-4,209	-5,684	-6,933	-8,863	-8,965
Ohio	39	14,147	12,370	9,942	14,465	23,329	24,092
Oklahoma	40	-9,469	-7,568	-5,372	-4,716	-7,249	-5,756
Oregon	41	4,954	1,496	-11,214	-11,034	-11,818	-9,426
Pennsylvania	42	-14,084	-7,337	-16,258	-18,797	-20,875	-26,391
Rhode Island	44	4,566	4,636	4,915	5,031	5,228	5,343
South Carolina	45	319	3,666	8,151	1,148	4,015	-3,424
South Dakota	46	-3,277	-2,600	-2,403	-2,033	-2,170	-1,742
Tennessee	47	17,975	18,971	13,517	4,574	7,837	6,729
Texas	48	-4,620	-5,011	217	4,023	7,941	12,008
Utah	49	107	1,039	1,223	1,335	870	-666
Vermont	50	6,507	5,936	5,473	6,848	6,371	6,801
Virginia	51	18,897	16,996	18,143	19,561	21,435	19,943
Washington	53	-11,285	-20,138	-19,221	-18,008	-9,591	-7,740
West virginia	54	-48,166	-50,801	-46,820	-50,996	-54,882	-57,083
Wisconsin	55	2,956	4,319	4,298	3,881	2,610	3,915
Wyoming	56	-14,580	-17,757	-18,393	-16,172	-20,862	-24,301
Total		62,071	80,199	78,720	75,068	99,881	83,126

Table 8.3 Annual Interstate Electricity Transfers [15,16,17,18,19,20]

9 EVALUATION OF MARKET SHARING

E.H. Pechan & Associates, Inc. (Pechan) developed a market sharing algorithm for the Dispatching Module (DISPATCH) as a means of improving the linear program's distribution of capacity factor outputs. As originally conceived, the dispatch linear program has many more constraints than decision variables, making the basis size small relative to the number of units available for dispatch. The effect of small basis size is that dispatch trade-offs are made among a few units, whose capacity factors reflect economic trade-offs. Capacity factors for other units are very low (perhaps zero when left unconstrained), indicating that only a few units share the task of meeting load.

While such is an expectable result of a linear program dispatch minimizing variable cost on an annual basis, it does not agree with utility practice based on hour-to-hour operating constraints. Accordingly, the market sharing approach, whose effect is to distribute generation among units, was examined [9]. The market sharing algorithm results in an improvement in the distribution of capacity factors and in the accuracy of emissions projections for historical years. Because the procedure relies on an ad hoc method for constraining an annual simulation to reflect actual operating conditions, it was used only temporarily until minimum capacity factor constraints by generating technology type were installed in DISPATCH. The market sharing procedure is no longer used. The constraints currently in use reflect unit turn-down ratio (e.g., for coal-fired units) or peak load operation (e.g., for peaking turbines) of generating units [9]. Test results using these constraints are described in section 10.

9.1 Introduction

This study is a follow-on to the study presented in Chapter 8 and has been developed to determine if the remaining differences in AUSM and the 1980 NURF Inventory SO_2 emissions can be reduced further by redefining utilization levels among coal-fired units, and possibly across fuel types. Although these changes

	1980 Historical	AUSM Base Case	Percent Difference
Emissions (Million tons)	1.145	1.367	19.4%
Generation (Gigawatt hours)			
- Oil	7237	4618	-36.2%
- Gas	1406	1782	26.7%
- Coal	66910	68378	2.2%
- Nuclear	27741	31480	13.5%
- Hydro	122	112	-8.2%
TOTAL	103416	106370	

Table 9.1 1980 Generation by Fuel Type for Illinois

	1980 Historical	AUSM Base Case	Percent Difference
Emissions (Million tons)	1.048	1.213	15.7%
Generation (Gigawatt hours)			
- Oil	124	127	2.4%
- Gas	158	26	-83.5%
- Coal	53883	52504	-2.6%
- Nuclear	0	0	0.0%
- Hydro	2939	3381	15.0%
TOTAL	57104	56038	

Table 9.2 1980 Generation by Fuel Type for Kentucky

may affect states whose SO_2 emissions have been accurately forecasted, this analysis will focus on the three states (Illinois, Kentucky, and Florida) whose emissions forecasts were still poor even after addressing the issues identified in Chapter 8.

Preliminary investigation indicates that generation by fuel type may be an issue. Coal-fired generation levels in Illinois and Kentucky are within 3 percent of the Edison Electric Institute (EEI) [15 - 20] values for these two states (see Tables 9.1 and 9.2). On the other hand, coal-fired generation in Florida differs by nearly 30 percent from the EEI values (see Table 9.3). This either indicates that generation by fuel type may be a contributing factor to emission differences in Florida or that interstate transfers into Florida exist but are not being accounted for because Florida is modeled as a single state region. Later analysis determined that unaccounted for interstate transfers were a major factor affecting the Florida results.

Coal unit utilization levels have been selected as the focus of this study for two related reasons: 1) accurate representation of coal unit utilization levels are critical to successfully forecasting SO_2 emissions, and 2) modeled unit-level capacity factors do not compare with those defined in the 1980 NURF Inventory. Preliminary analyses supporting the second point are presented below.

A cumulative distribution plot comparing 1980 NURF Inventory coal plant capacity factors in Illinois with those generated by DISPATCH is presented in Figure 9.1. The two distributions are very different, with AUSM taking on the characteristic of a step function. This is because AUSM essentially dispatches coal plants at four levels:

- zero annual capacity factor (CF);
- peak day availability for the peak load segment and zero for the remaining segments (8 percent annual CF);
- peak day availability for the peak load segment, net availability for the cycling load, and zero for the base load (24 percent annual CF); and
- peak day availability for the peak load segment, and net availability for the cycle and base loads (76 percent annual CF).

	1980 Historical	AUSM Base Case	Percent Difference
Emissions (Million tons)	0.722	0.478	-33.8%
Generation (Gigawatt hours)			
- Oil	44352	42137	-5.0%
- Gas	14860	14650	-1.4%
- Coal	19737	25648	29.9%
- Nuclear	16737	17120	2.3%
- Hydro	215	224	4.2%
TOTAL	95901	99779	

Table 9.3 1980 Generation by Fuel Type for Florida

A majority (approximately 65 percent) of total AUSM capacity in Illinois is utilized at its maximum capacity level of 76 percent, whereas corresponding 1980 NURF Inventory capacity operates at all utilization levels with no single level dominating. This distribution indicates the possibility that AUSM derives its 1980 emissions from fewer sources than the 1980 NURF Inventory, with these sources operating at higher utilization levels.

To determine if emissions are coming from fewer sources, a preliminary analysis of the top ten emitting units in Illinois and Kentucky has been conducted. Results indicate that 62 percent of 1980 SO_2 emissions in Illinois come from the top ten emitting units in that state, and 55 percent of the emissions come from the top 7 emitting units (representing only three plants). These units operate at their maximum capacity factor of 76 percent in the AUSM simulation, as compared to the 1980 NURF Inventory average capacity factor of 60 percent. This equates to an excess of 2200 tons of SO_2 in 1980 coming from the top ten emitting units in the AUSM simulation. Table 9.4 presents AUSM and 1980 NURF Inventory capacity factors for the top seven emitting units in Illinois.

PLANT NAME	HEAT RATE (Btu/kWh)	COST		CAPACITY FACTOR		AUSM EMISSIONS (Tons of SO_2)
		FUEL (Cents/MMBtu)	O & M	1980 NURF INVENTORY (Mills/kWh)	AUSM	
Coffeen 1	11,163	115.0	0.26	0.35	0.76	98,501
Coffeen 2	11,162	115.0	0.18	0.53	0.76	160,230
Kincaid 1	11,016	137.7	0.16	0.61	0.76	137,040
Kincaid 2	11,016	137.7	0.16	0.57	0.76	137,040
Baldwin 1	9,852	113.1	0.15	0.60	0.76	103,490
Baldwin 2	9,852	113.1	0.15	0.70	0.76	103,490
Baldwin 3	9,856	113.1	0.15	0.65	0.76	103,530
Total						843,323

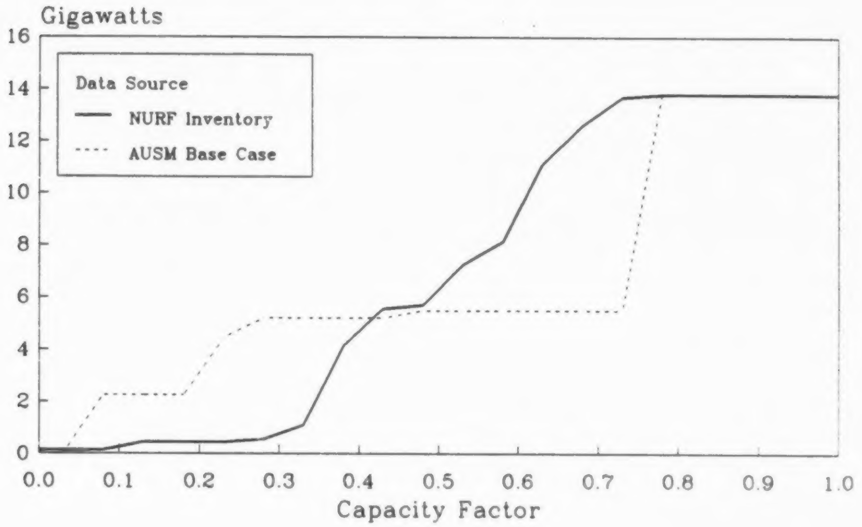
Table 9.4 Illinois Top Seven Emitting Units

Similarly, the top ten SO_2 emitting units in Kentucky emit about 60 percent of total 1980 SO_2 emissions, with the top three units (all from one plant) producing 34 percent of the state's emissions. The AUSM capacity factor for these ten units is 76 percent (their maximum capacity factor), while the corresponding 1980 NURF Inventory average capacity factor is 51 percent. Table 9.5 presents capacity factors for the top ten emitting units in Kentucky.

PLANT NAME	HEAT RATE (Btu/kWh)	COST		CAPACITY FACTOR		AUSM EMISSIONS (Tons of SO_2)
		FUEL (Cents/MMBtu)	O & M	1980 NURF INVENTORY (Mills/kWh)	AUSM	
PARADISE	9,955	94.1	0.11	0.34	0.76	256,043
PARADISE	9,950	94.1	0.14	0.51	0.76	154,809
PARADISE	9,950	94.1	0.14	0.67	0.76	154,809
GHENT	10,279	140.8	0.14	0.63	0.76	63,988
MILL CREEK	9,991	121.9	0.27	0.56	0.76	61,188
GHENT	10,279	140.8	0.18	0.49	0.76	60,575
BIG SANDY	9,664	127.1	0.12	0.62	0.76	51,600
BROWN	10,837	131.9	0.21	0.65	0.76	46,894
ELMER SMITH	10,504	140.0	0.27	0.49	0.76	41,899
CANE RUN	10,999	118.0	0.62	0.32	0.76	22,993
TOTAL						914,798

Table 9.5 Kentucky Top Ten Emitting Units

Figure 9.1 Capacity Factor Distribution
Cumulative for Illinois, 1980
NURF vs AUSM Base Case



Since the AUSM uses a least cost dispatch LP, simulated utilization levels are based on unit operating costs (e.g., low fuel costs or high efficiency levels tend to dictate high utilization levels). The 1980 NURF Inventory, however, reports that various units operate at different levels even though they are from the same plant with virtually identical operating costs (see Tables 9.4 and 9.5). This indicates that some issues which may have a significant impact on determining utilization levels, and thereby emissions, at individual generating units are not modeled by the AUSM dispatch algorithm.

An optional market sharing algorithm exists within AUSM which will redistribute coal generation derived from the dispatch LP. By invoking this option, utilization effects which could not be directly included in the dispatch LP will be simulated. This study evaluates the market sharing algorithm for its ability to 1) provide a more representative distribution of capacity factors, and 2) provide a distribution of capacity factors that results in an emissions level which accurately forecasts historical emissions.

9.2 Approach

The state model within AUSM is executed with the market sharing option invoked and using the NAPAP Reference Base Case scenario files. This run should have no effect on state generation by fuel type because market sharing simply redistributes generation among coal plants. The redistribution results in an altered pattern of coal plant utilization and results in different emissions and coal usage forecasts.

9.2.1 Objectives

The objective of this study is to determine if the market sharing algorithm, which to date is not a standard component in the model configuration, should be employed to improve the AUSM ability to forecast SO_2 emissions. This determination will be made based on two evaluation criteria:

1) Does the resulting coal plant capacity factor distribution better represent historical utilization patterns?
2) Does AUSM forecast SO_2 emissions more accurately by using the market sharing algorithm?

9.2.2 Procedures

The AUSM state-level model is submitted for the Base case with the market sharing option invoked. To invoke the market sharing option, the dispatch switch in the state scenario directives file is set to "1" and the code to bypass the market sharing algorithm is eliminated. No interstate power transfer calibration features are employed in the run. Improvements in the emissions forecast should be measured against the emissions forecast for the Base case. Simulation results are analyzed at the state level for the top ten emitting states, as well as at the national level.

The market sharing algorithm is heuristic and this option should be accepted only if the heuristic can be validated. One of the best ways to validate the algorithm is to compare its performance to actual data which represent the system being modeled. Both capacity factors and SO_2 emissions are included in the evaluation criteria because these two parameters are closely linked. If the algorithm produces a capacity factor distribution that resembles observed distributions but the emissions estimates are not improved (or they degrade), then the algorithm is not acceptable. Use of SO_2 emissions as an evaluation criteria also assists in determining whether modified capacity factor distributions (which may appear to better approximate observed patterns at the aggregate level) actually produce improvements.

9.3 Input Data

There are no special input data requirements for this study.

9.4 Results

The resulting 1980 SO_2 emissions have been analyzed at three levels: the aggregate nation, the top ten emitting states (individually and aggregated), and the remaining 38 states (aggregated). Table 9.6 presents the SO_2 emissions corresponding to these three levels. National totals for this study are closer to the 1980 NURF Inventory totals, but the aggregate top ten and lower 38 show no major improvements in SO_2 emissions. This can be seen in Figure 9.2 for the aggregate top ten emitting states. Although there is little change in emissions for these ten states as a group, some improvement can be seen at the individual state level. For example, six of the top ten states show improvement in replicating 1980 NURF Inventory SO_2 emissions levels, while only two states degrade in performance. Note that none of the states which violated the +/-10 percent criteria came into compliance as a result of employing the market sharing algorithm.

1980 AUSM Market Sharing Study Results vs. 1980 NURF Inventory

		Emissions	
AUSM SO_2 Emissions Performance Relative to 1980 NURF Inventory	State/ Region	AUSM	1980 NURF
		(1000 tons of SO_2)	
AUSM < -10% of NURF	Lower 38	4919	5567
-10% <= AUSM < -5%	None		
-5% <= AUSM < 0%	Indiana	1568	1580
0% <= AUSM < 5%	Nation	18231	17630
	Ohio	2220	2207
5% <= AUSM < 10%	Pennsylvania	1602	1504
	W. Virginia	1041	968
AUSM > 10% of NURF	Top Ten	13312	12063
	Missouri	1457	1175
	Illinois	1360	1145
	Kentucky	1187	1048
	Tennessee	1113	959
	Georgia	900	758
	Florida	864	720

Table 9.6 SO_2 Emissions for the Top Ten Emitting States

Analysis of the capacity factors resulting from employing the market sharing algorithm shows that the algorithm adequately duplicates the capacity factor distribution implied by the 1980 NURF Inventory. This can be seen in Figure 9.3 for Illinois. The amount of capacity operating at each utilization level is very similar, especially at the low end of the capacity factor spectrum. The ability of the algorithm to replicate utilization levels for individual units is not better than what the linear programming technique can do, i.e. only 62 percent of the 1980 emissions generated under the market sharing algorithm originate from the plant which the 1980 NURF Inventory identifies identifies as being responsible for these emissions. Therefore, advantage of employing the market sharing algorithm is questionable.

The market sharing algorithm also appears to have an additional problem in that it fails to recognize coal unit availability limitations. The algorithm increases the capacity factor of 2000 megawatts of capacity above the 76 percent maximum specified as a constraint. Such a level of utilization indicates that these units violate planned and unplanned outage rates which constrain utilization of individual units in the dispatch algorithm.

9.5 Conclusions

The market sharing algorithm clearly has the ability to transform a set of scattered coal plant capacity factors into a set of utilization levels which presents a curve more representative of values implied by the 1980 NURF Inventory. This transformation does not have a positive impact (and in fact may have a negative impact) on AUSM ability to forecast a set of state-level SO_2 emissions for the historical time period. The basic problem appears to be with the quality of information being supplied to the market sharing routine as opposed to the market sharing algorithm itself. Some improvements in results may be achieved if the planned and unplanned outage rate constraints can be incorporated into the market sharing routine.

Figure 9.2 1980 SO2 Emissions
Calibration Study: AUSM & NURF
Top 10 Emitting States

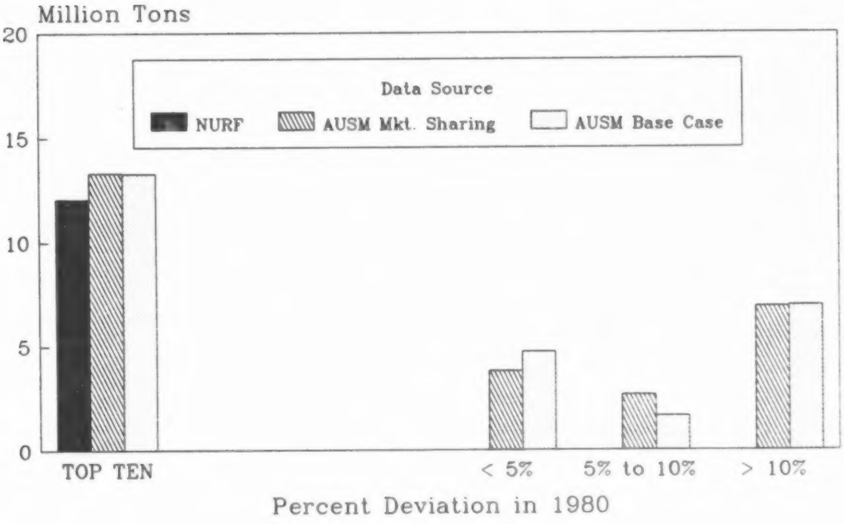
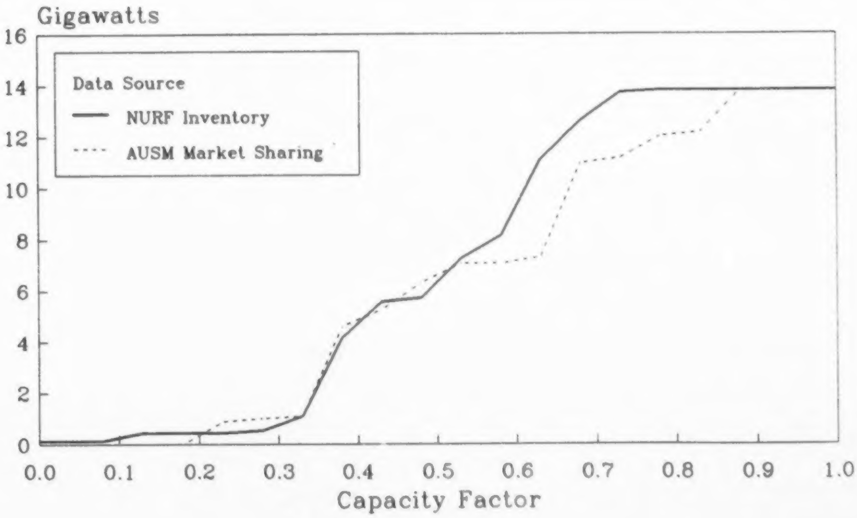


Figure 9.3 Capacity Factor Distribution
Cumulative for Illinois, 1980
NURF vs AUSM Market Sharing Study



10 USE OF MINIMUM CAPACITY FACTORS

The objective of this study was to develop a method for incorporating unit level minimum capacity factors in the Dispatching Module (DISPATCH) module linear program to increase the accuracy of SO_2 emission simulations during historical years. Two criteria were established for evaluating results: SO_2 emissions simulated by AUSM were compared with historic SO_2 emissions and the distribution of simulated capacity factors was compared with the distribution of historic capacity factors. Acceptable error ranges were established for individual state and national SO_2 differences. Capacity factor distributions were evaluated by considering reduction in bimodality.

Results of this study led to incorporation of unit level capacity factor minima. These were ultimately implemented as lower bounds, as opposed to constraints, to improve solution efficiency.

10.1 Introduction

Since SO_2 emissions levels are directly linked to coal unit utilization levels, capacity factor distributions corresponding to the AUSM Base case results and historical values have been compared for Illinois and Kentucky. As Figures 10.1 and 10.2 show, utilization levels for these two states are very different from the 1980 NURF Inventory values. This may be due to the minimum capacity factor constraint in DISPATCH. This constraint requires all units within a technology category to maintain a generating level which, when averaged, will be above a minimum capacity level specified for that technology category. Accordingly, some base load units need not operate at all. This, of course, is unrealistic since the turndown ratio (or the economical minimum operating level of an active plant) typically associated with a coal unit is 0.2 to 0.3. Close inspection of the unit-specific information reveals that, due to the nature of a cost minimization problem, units firing cheaper high sulfur coal are being used to their maximum capacity level while more expensive low sulfur coal-fired units are used at a level much less than the typical coal plant of this type (see Figures 10.3 through 10.6). These observations indicate that a unit-level minimum capacity factor constraint should be added to the DISPATCH module.

10.2 Approach

A separate dispatch algorithm, constructed outside the state-level model framework, has been developed to measure the effects of including a unit-level minimum capacity factor constraint in the problem formulation. MPS-III (developed by Ketron) is the LP package used to develop this duplicate algorithm because it is superior to the XMP LP procedure when it comes to modifying and testing formulations. To limit the scope of this assessment, test runs are conducted

Figure 10.1 Coal Unit Capacity Factors
Comparison: NURF & AUSM Transfer Study
Illinois, 1980

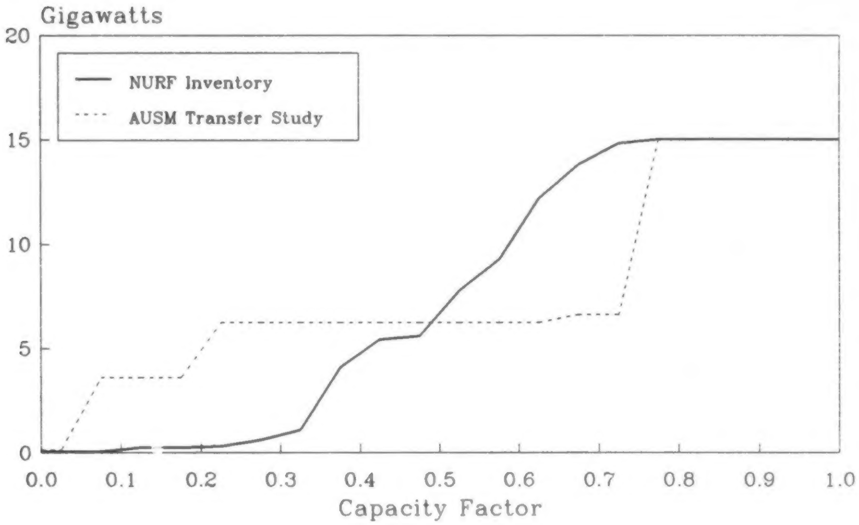


Figure 10.2 Coal Unit Capacity Factors
Comparison: NURF & AUSM Transfer Study
Kentucky, 1980

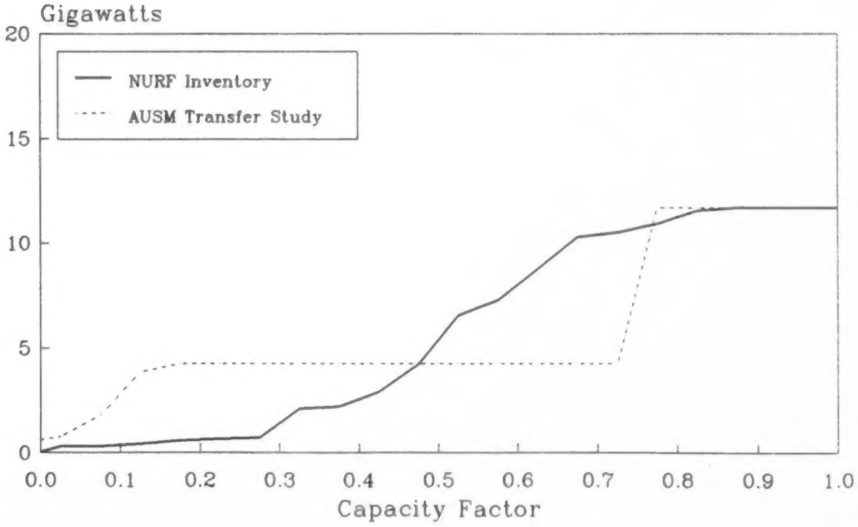


Figure 10.3 High Sulfur Coal Units

Comparison: NURF & AUSM Transfer Study

Illinois, 1980

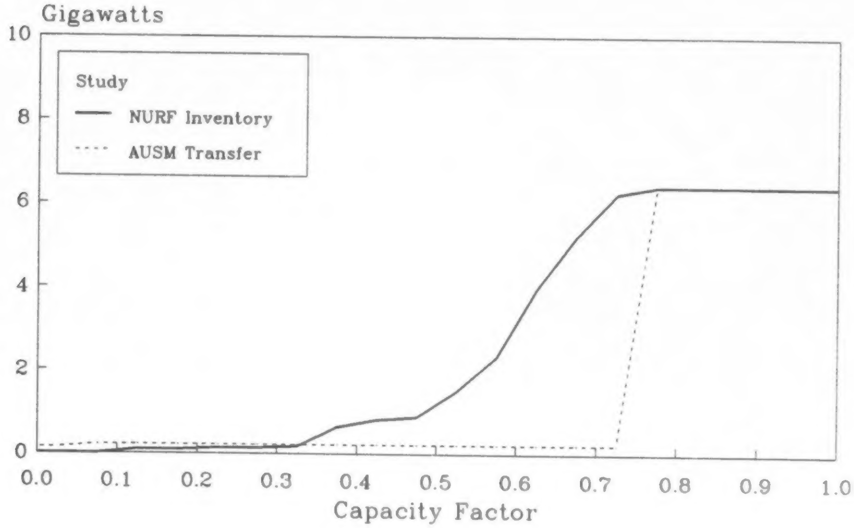


Figure 10.4 Low Sulfur Coal Units

Comparison: NURF & AUSM Transfer Study

Illinois, 1980

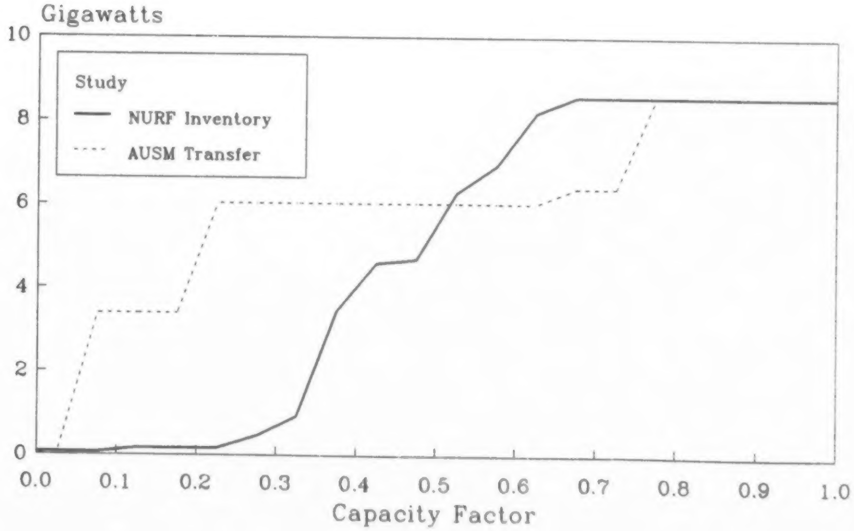


Figure 10.5 High Sulfur Coal Units
Comparison: NURF & AUSM Transfer Study
Kentucky, 1980

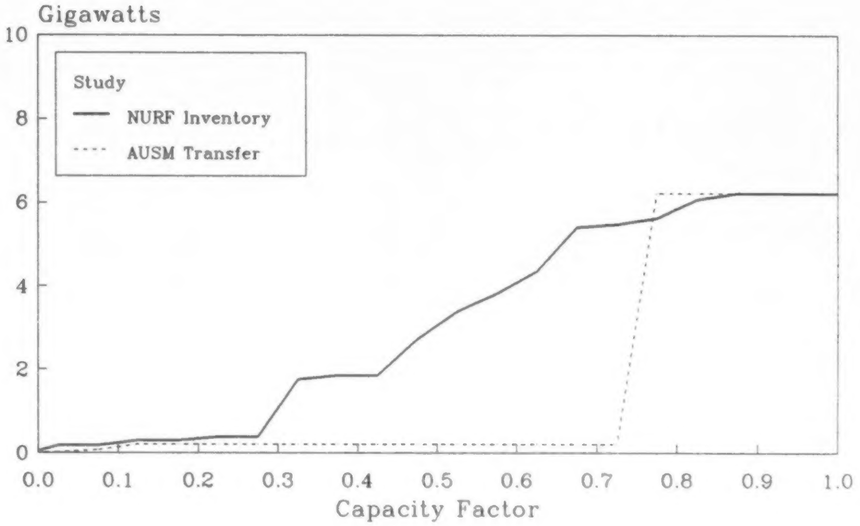
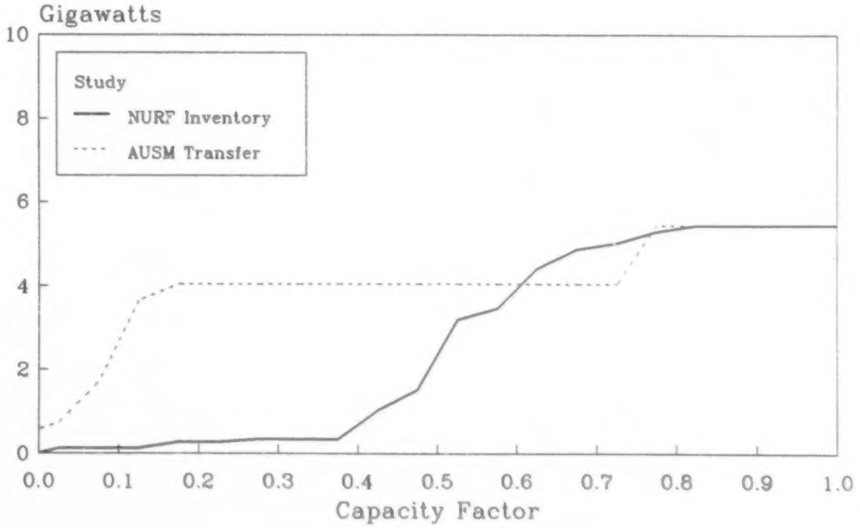


Figure 10.6 Low Sulfur Coal Units
Comparison: NURF & AUSM Transfer Study
Kentucky, 1980



for 1980 only. As in DISPATCH, a three step load duration curve is used. A validation run and three variations in applying a minimum capacity factor constraint to the formulation have been established for this study.

10.2.1 Objectives

The objective is to more accurately duplicate SO_2 emission and capacity factor utilization levels by incorporating a unit-level capacity factor constraint into the problem statement and constraint base. With this change, generation of under-utilized low sulfur coal-fired units is anticipated to increase, possibly displacing some of high sulfur coal-fired generating capacity. The impact can be gauged by comparing the new AUSM generation and emissions levels to actual 1980 values.

10.2.2 Procedures

A validation test and three variations of the formulation have been established for this analysis. These are described below.

Validation Test. The minimum capacity factor constraint in the new LP formulation is initially set equal to zero. Results from this test are then compared to past AUSM results to verify the accuracy of the new MPS-III dispatch algorithm. Runs are submitted for the top ten SO_2 emitting states which represent 69 percent of total SO_2 emissions in 1980. Resulting SO_2 emission levels and generation levels are then compared to DISPATCH results for the Base case.

Dispatch Test 1: Minimum capacity factor for all units and all load segments. Minimum capacity factors are set for each generation unit and are applied across all load segments. Again, runs are submitted for the top ten SO_2 emitting states. SO_2 emission and generation levels were compared to historical 1980 values.

Dispatch Test 2: Minimum capacity factor for coal units only and for all load segments. Minimum capacity factors are set only for baseload coal-fired units and apply across all load segments. Resulting SO_2 emission and generation levels are compared to the historical 1980 values.

Dispatch Test 3: Minimum capacity factor for all units and for the appropriate load segment. The minimum capacity factor constraint is applied only to the load segment corresponding a given unit type. For example:

Peaking units: The minimum generation must be met in the peak load segment.
Cycling units: The minimum generation must be met in both the peak and cycling load segments.
Baseload units: The minimum generation must be met in all three load segments.

Runs were submitted for the ten states emitting the most SO_2 in 1980. SO_2 emission and generation results from these runs were then compared to historical 1980 values (Table 10.1). If a given test produced results close to historical values, the analysis was expanded to include the top fifteen emitting states (accounting for 82 percent of the national SO_2 emissions in 1980).

Top Ten Sulfur Dioxide Emitting States in 1980

	1980 Historical	AUSM Base Case	Transfer Study	Dispatch			
				Valid. Test	Test 1	Test 2	Test 3
Emissions (Million tons)	12.073	13.298 (10.2%)	12.886 (6.7%)	12.847 (6.4%)	12.391 (2.6%)	12.562 (4.1%)	12.533 (3.8%)
Generation (Gigawatt hours)							
- Oil	65220	61718 (-5.4%)	54494 (-16.4%)	52125 (-20.1%)	57867 (-11.3%)	47201 (-27.6%)	50157 (-23.1%)
- Gas	18635	18031 (-3.2%)	17547 (-5.8%)	17763 (-4.7%)	19430 (4.3%)	22567 (21.1%)	22931 (23.1%)
- Coal	632933	660273 (4.3%)	630284 (-0.4%)	629617 (-0.5%)	622208 (-1.7%)	629737 (-0.5%)	626417 (-1.0%)
- Nuclear	67645	77199 (14.1%)	77199 (14.1%)	80028 (18.3%)	80028 (18.3%)	80028 (18.3%)	80028 (18.3%)
- Hydro	18608	23504 (26.3%)	23504 (26.3%)	23508 (26.3%)	23508 (26.3%)	23508 (26.3%)	23508 (26.3%)
Total	803041	840725	803028	803042	803042	803042	803042

Table 10.1 Emission and Generation Levels: Minimum CF Tests

Placing a minimum capacity factor constraint on each unit is anticipated to cause the more expensive (previously under-utilized) low emitting coal-fired units to increase their generation level. To observe this effect, coal-fired units are grouped by SO_2 emission rate and the corresponding cumulative capacity factors are observed. A value of 28 pounds of SO_2 per MWh has been selected as the break point where "clean" plants are distinguished from "dirty" plants. This breakpoint corresponds to plants having an emissions standard in the range of

2.0 to 2.8 pounds of SO_2 per MMBtu, depending on the heat rate of the generating unit.

Top Ten Sulfur Dioxide Emitting States in 1980

(Million Tons)

	1980 Historical	AUSM Base Case	Transfer Study	Dispatch			
				Valid. Test	Test 1	Test 2	Test 3
Illinois	1.145	1.367 (19.4%)	1.351 (18.0%)	1.352 (18.1%)	1.173 (2.4%)	1.225 (7.0%)	1.216 (6.2%)
Pennsylvania	1.508	1.637 (8.5%)	1.571 (4.2%)	1.555 (3.1%)	1.429 (-5.3%)	1.484 (-1.6%)	1.473 (-2.4%)
Georgia	0.759	0.888 (16.9%)	0.716 (-5.7%)	0.715 (-5.9%)	0.732 (-3.6%)	0.731 (-3.7%)	0.732 (-3.7%)
Tennessee	0.959	1.116 (16.4%)	1.041 (8.6%)	1.041 (8.6%)	1.034 (7.8%)	1.035 (8.0%)	1.035 (8.0%)
Florida	0.722	0.864 (19.7%)	0.849 (17.6%)	0.854 (18.3%)	0.764 (5.9%)	0.802 (11.1%)	0.802 (11.1%)
Missouri	1.175	1.491 (26.9%)	1.176 (0.1%)	1.169 (-0.5%)	1.173 (-0.2%)	1.173 (-0.1%)	1.171 (-0.3%)
Indiana	1.580	1.574 (-0.4%)	1.715 (8.6%)	1.717 (8.7%)	1.654 (4.7%)	1.656 (4.9%)	1.656 (4.8%)
West Virginia	.968	0.992 (2.5%)	0.983 (1.5%)	0.981 (1.4%)	0.968 (0.0%)	0.969 (0.1%)	0.969 (0.1%)
Kentucky	1.048	1.213 (15.7%)	1.232 (17.5%)	1.233 (17.6%)	1.149 (9.6%)	1.149 (9.6%)	1.149 (9.6%)
Ohio	2.209	2.156 (-2.4%)	2.252 (2.0%)	2.229 (0.9%)	2.316 (4.8%)	2.338 (5.9%)	2.331 (5.5%)

Table 10.2 Emission Levels from Minimum CF Tests

10.3 Input Data

The data used in each of these runs are similar to data used in the NAPAP Reference Base case and in the study presented in Chapter 7. Data are similar with respect to unit characteristics, capital and operating costs (including fuel costs), capacity factors, availability levels, and emission factors. The same average minimum capacity factor data are used for the technology-level capacity factor constraint run and the unit-level minimum capacity factor constraint run.

Figure 10.7 1980 S02 Emissions
Minimum Capacity Factor Use
Top 10 Emitting States: AUSM vs NURF

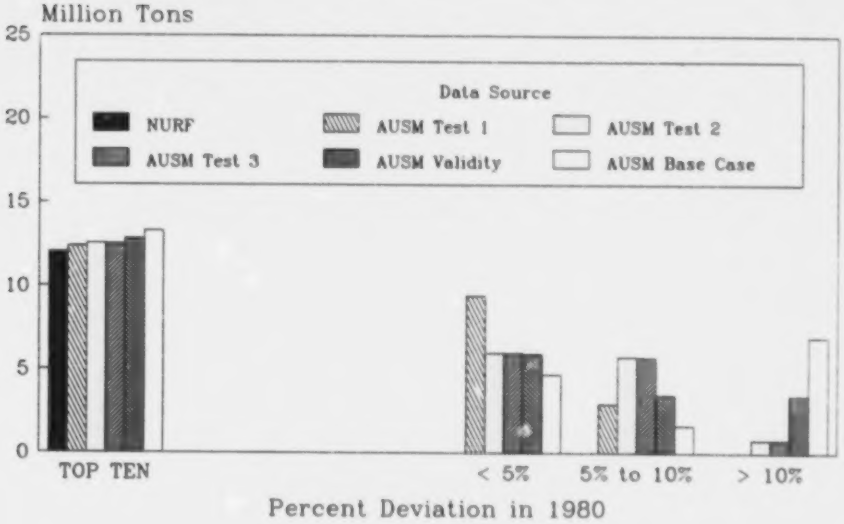


Figure 10.8 Coal Unit Capacity
Comparison: NURF & AUSM Dispatch
Illinois, 1980

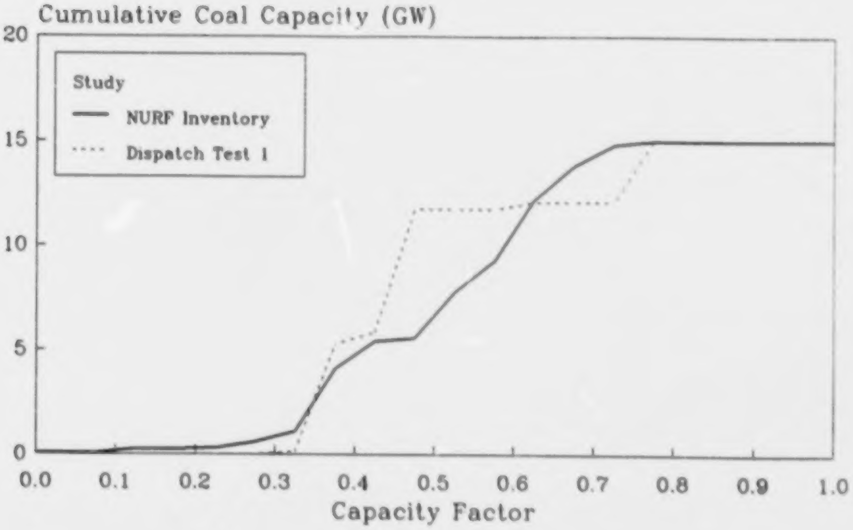


Figure 10.9 Coal Unit Capacity

Comparison: NURF & AUSM Dispatch

Kentucky, 1980

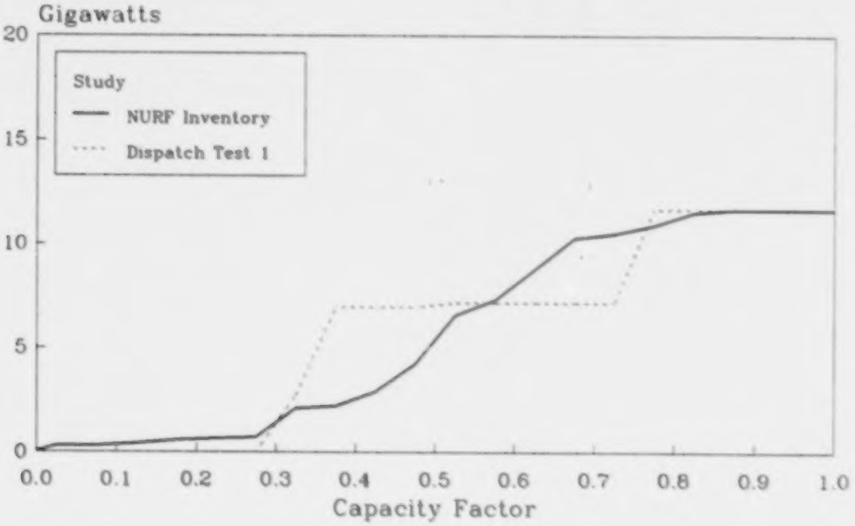
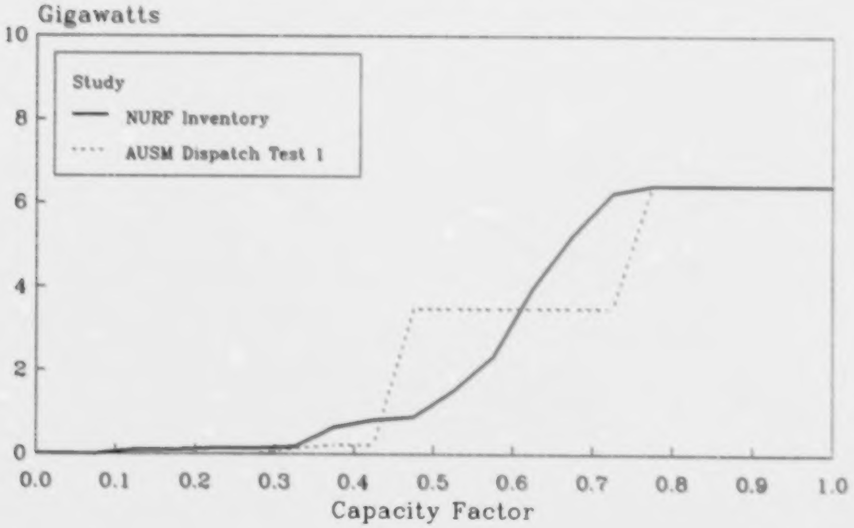


Figure 10.10 High Sulfur Coal Capacity

Comparison: NURF & AUSM Dispatch

Illinois, 1980



10.4 Results

The validation test succeeded in duplicating SO_2 emissions to within one percent of that reported in the historical transfer study (Chapter 7) for each of the top ten emitting states. Generation levels by fuel type also compare favorably (Appendix A). As a result, the MPS-III version of the dispatching algorithm has been used in the remaining tests.

1980 AUSM Dispatch Study Results vs. 1980 NURF Inventory

AUSM SO_2 Emissions Performance Relative to 1980 NURF Inventory	State/ Region	Emissions AUSM (1000 tons of SO_2)	Emissions 1980 NURF (1000 tons of SO_2)
AUSM < -10% of NURF	ALABAMA	571	491
	NORTH CAROLINA	445	396
-10% <= AUSM < -5%	PENNSYLVANIA	1504	1429
	GEORGIA	758	732
-5% <= AUSM < 0%	WISCONSIN	461	460
	MISSOURI	1175	1173
0% <= AUSM < 5%	TOP 15	14596	14892
	W. VIRGINIA	968	968
	OHIO	2207	2316
	INDIANA	1580	1654
	ILLINOIS	1145	1173
5% <= AUSM < 10%	MICHIGAN	566	596
	NEW YORK	489	515
	KENTUCKY	1048	1149
	TENNESSEE	959	1034
	FLORIDA	720	764
AUSM > 10% of NURF	None		

Table 10.3 SO_2 Emissions for Top Fifteen Emitting States

Aggregate AUSM forecasts of 1980 emissions and generation by fuel type for the top ten emitting states are presented in Table 10.1. Included among these forecasts are results from the validation test, the three Dispatch tests, the NAPAP Reference Base Case and the historical transfer study from Chapter 7. Each set of results is compared to historical 1980 values. Emissions corresponding to each of the top ten emitting states are reported for each run in Table 10.2; and, state-level generation results are presented in Appendix A.

The three variations in the unit-level minimum capacity factor constraint were successful in bringing SO_2 emission levels closer to historical levels (see Figure 10.7), only Dispatch Test 1 met the criterion that SO_2 emissions for each state be within 10 percent of historical values. (Note: Dispatch Test 1 places a minimum capacity factor constraint on all generating units over all three load segments.) Also, this constraint caused coal-fired units in Illinois and Kentucky to operate more closely to historical levels, both at the aggregate level (see Figures 10.8 and 10.9) and disaggregated by high and low sulfur coal (see Figures 10.10 through 10.13). As anticipated, Figures 10.10 through 10.13 show that increased generation from the previously under-utilized low sulfur coal-fired units resulted in the operating level of some of the high sulfur coal-fired units to be reduced, thereby being more in line with historical operating levels.

The unit-level minimum capacity factor constraint had very little impact on model results for states like Florida. This is because Florida already dispatched its units at their maximum level, leaving little margin for trade-offs in operating levels. This is depicted in Figure 10.14 through 10.17 for low and high sulfur coal-fired units.

Results from Dispatch Test 1 produced such significant improvements in forecasting SO_2 emissions that the test was expanded to the top fifteen emitting states. Improved performance in AUSM's ability to forecast emissions was also observed for this group of states. Table 10.3 presents the resulting SO_2 emissions forecasts for the fifteen states. At the aggregate level, 1980 SO_2 emissions forecast for the fifteen state group are within 2.0 percent of the 1980 NURF Inventory value. This forecast represents over a 60 percent reduction in error over the Base case model run.

10.5 Conclusions

Implementing minimum capacity factor requirements for individual units, especially those not operating at their maximum capacity, has improved the model calibration performance. Capacity distributions which are better representations of historical values have been achieved. More importantly, this new capacity distribution has brought emissions more in line with historical values, without having a major impact on technology-specific generation levels. Therefore, it is important that unit-level minimum capacity factor constraints be incorporated in future model runs.

Figure 10.11 Low Sulfur Coal Capacity
Comparison: NURF & AUSM Dispatch Study
Illinoios, 1980

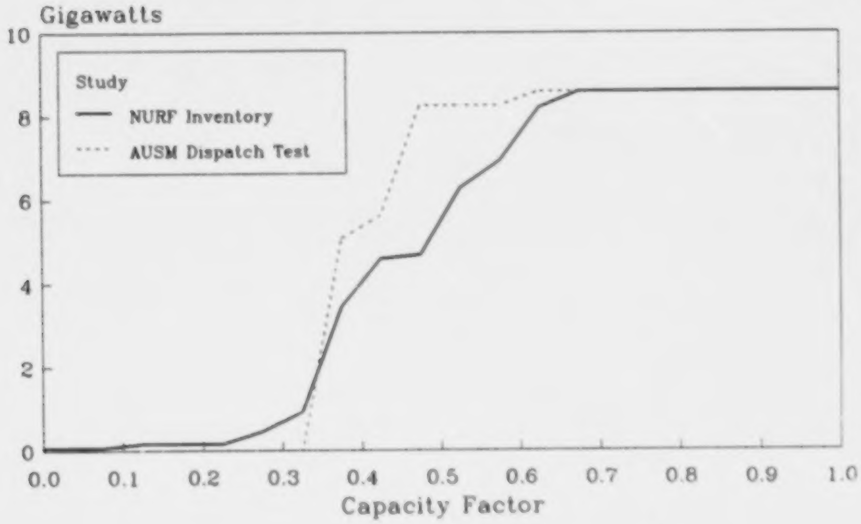


Figure 10.12 High Sulfur Coal Capacity
Comparison: NURF & AUSM Dispatch
Kentucky, 1980

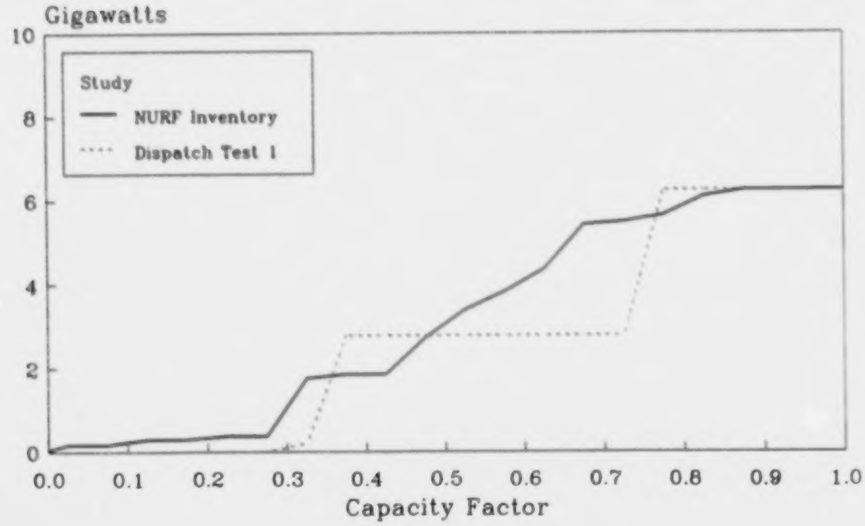


Figure 10.13 Low Sulfur Coal Capacity

Comparison: NURF & AUSM Dispatch

Kentucky, 1980

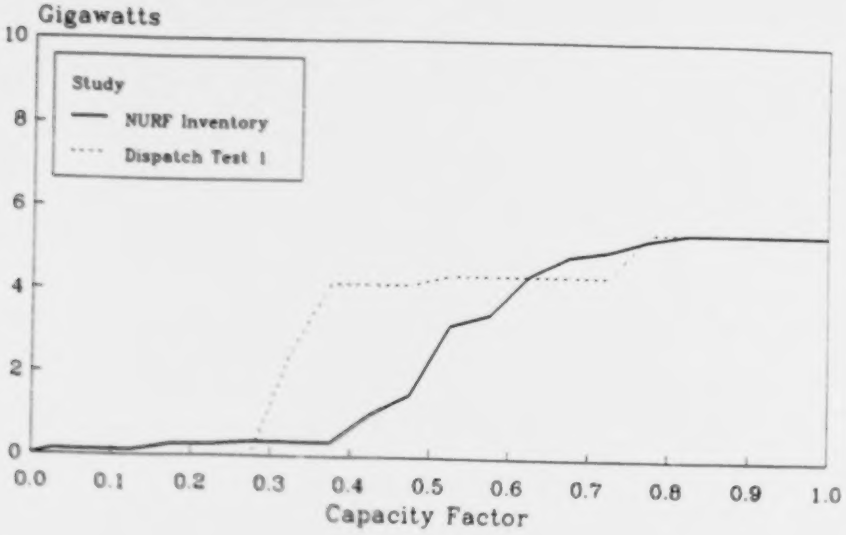


Figure 10.14 High Sulfur Coal Capacity

Comparison: NURF & AUSM Dispatch

Florida, 1980

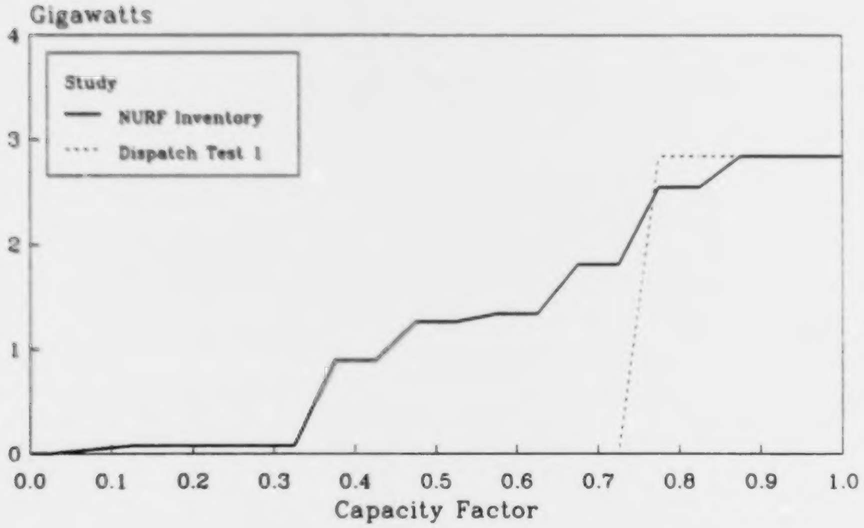


Figure 10.15 Low Sulfur Coal Capacity

Comparison: NURF & AUSM Dispatch

Florida, 1980

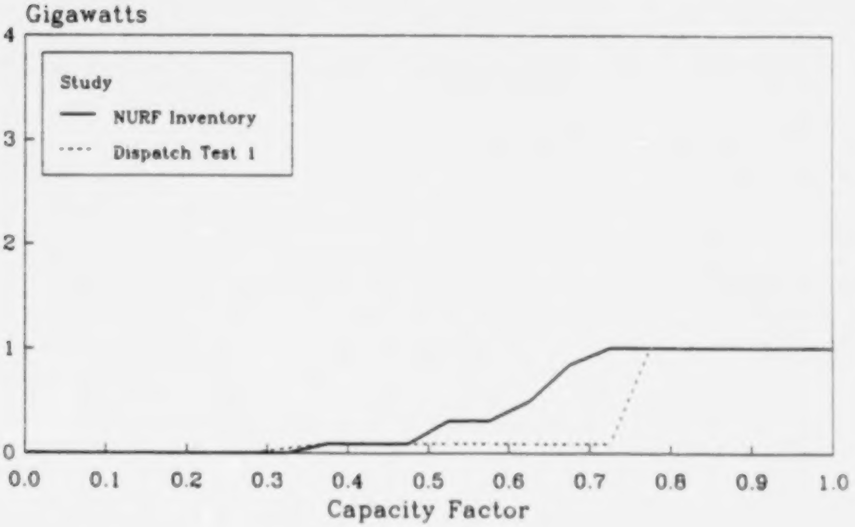


Figure 10.16 High Sulfur Coal Capacity

Comparison: NURF & AUSM Transfer Study

Florida, 1980

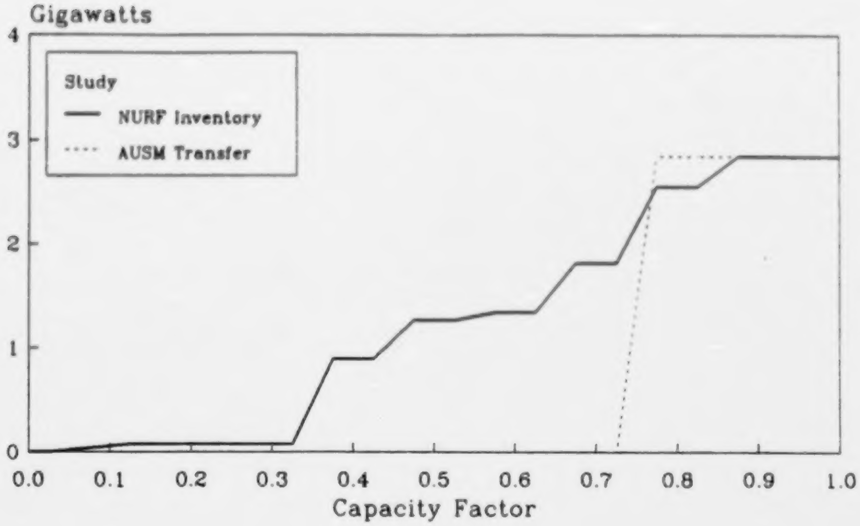
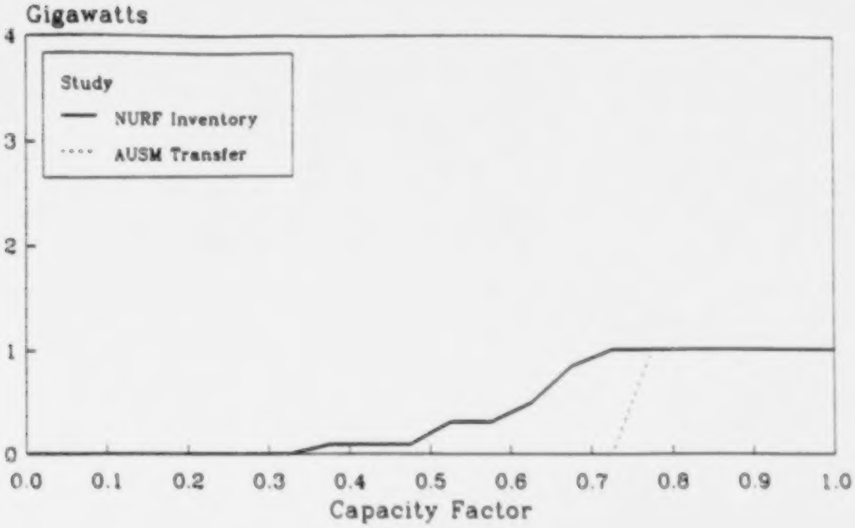


Figure 10.17 Low Sulfur Coal Capacity

Comparison: NURF & AUSM Transfer Study

Florida, 1980



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APPENDIX A AUSM EMISSION AND GENERATION LEVELS

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions (Million tons)	2.209	2.156 (-2.4%)	2.252 (2.0%)	2.229 (0.9%)	2.316 (4.8%)	2.338 (5.9%)	2.331 (5.5%)
Generation (Gigawatt hours)							
- Oil	1036	1246 (20.3%)	1246 (20.3%)	1035 (-0.1%)	1410 (36.1%)	1035 (-0.1%)	1205 (16.3%)
- Gas	281	64 (-77.2%)	64 (-77.2%)	64.062 (-77.2%)	341.977 (21.7%)	64.062 (-77.2%)	200.016 (-28.8%)
- Coal	106800	99931 (-6.4%)	104711 (-2.0%)	104006 (-2.6%)	103353 (-3.2%)	104006 (-2.6%)	103701 (-2.9%)
- Nuclear	2119	4214 (98.9%)	4214 (98.9%)	5133 (142.2%)	5133 (142.2%)	5133 (142.2%)	5133 (142.2%)
- Hydro	6	5 (-16.7%)	5 (-16.7%)	4 (-38.6%)	4 (-38.6%)	4 (-38.6%)	4 (-38.6%)
Total	110242	105460	110240	110242	110242	110242	110242

Table A.1 Emission and Generation Levels for Ohio

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions (Million tons)	1.580	1.574 (-0.4%)	1.715 (8.6%)	1.717 (8.7%)	1.654 (4.7%)	1.656 (4.9%)	1.656 (4.8%)
Generation (Gigawatt hours)							
- Oil	348	543 (56.0%)	543 (56.0%)	261 (-25.0%)	261 (-25.0%)	261 (-25.0%)	261 (-25.0%)
- Gas	160	171 (6.9%)	171 (6.9%)	170.762 (6.7%)	170.762 (6.7%)	170.762 (6.7%)	170.762 (6.7%)
- Coal	69635	63643 (-8.6%)	69496 (-0.2%)	69781 (0.2%)	69781 (0.2%)	69781 (0.2%)	69781 (0.2%)
- Nuclear	0	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)
- Hydro	475	407 (-14.3%)	407 (-14.3%)	408 (-14.2%)	408 (-14.2%)	408 (-14.2%)	408 (-14.2%)
Total	70618	64764	70617	70620.5	70620.5	70620.5	70620.5

Table A.2 Emission and Generation Levels for Indiana

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions	1.508	1.637	1.571	1.555	1.429	1.484	1.473
(Million tons)		(8.5%)	(4.2%)	(3.1%)	(-5.3%)	(-1.6%)	(-2.4%)
Generation (Gigawatt hours)							
- Oil	10727	9866	8994	8275	11300	8275	9474
		(-8.0%)	(-16.2%)	(-22.9%)	(5.3%)	(-22.9%)	(-11.7%)
- Gas	200	123	123	123	223	123	123
		(-38.5%)	(-38.5%)	(-38.6%)	(11.7%)	(-38.6%)	(-38.6%)
- Coal	98756	105138	97121	96068	92943	96068	94870
		(6.5%)	(-1.7%)	(-2.7%)	(-5.9%)	(-2.7%)	(-3.9%)
- Nuclear	12093	15504	15504	17279	17279	17279	17279
		(28.2%)	(28.2%)	(42.9%)	(42.9%)	(42.9%)	(42.9%)
- Hydro	735	767	767	768	768	768	768
		(4.4%)	(4.4%)	(4.4%)	(4.4%)	(4.4%)	(4.4%)
Total	122511	131398	122509	122512.	122512.	122512.	122512.

Table A.3 Emission and Generation Levels for Pennsylvania

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions (Million Tons	1.175	1.491 (26.9%)	1.176 (0.1%)	1.169 (-0.5%)	1.173 (-0.2%)	1.173 (-0.1%)	1.171 (-0.3%)
Generation (Gigawatt hours)							
- Oil	244	290 (18.9%)	116 (-52.5%)	116 (-52.6%)	116 (-52.6%)	116 (-52.6%)	116 (-52.6%)
- Gas	1161	864 (-25.6%)	647 (-44.3%)	592 (-49.0%)	592 (-49.0%)	592 (-49.0%)	592 (-49.0%)
- Coal	46964	59661 (27.0%)	47308 (0.7%)	47366 (0.9%)	47366 (0.9%)	47366 (0.9%)	47366 (0.9%)
- Nuclear	0	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)
- Hydro	559	857 (53.3%)	857 (53.3%)	858 (53.5%)	858 (53.5%)	858 (53.5%)	858 (53.5%)
Total	48928	61672	48928	48931.3	48931.3	48931.3	48931.3

Table A.4 Emission and Generation Levels for Missouri

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions	1.145	1.367	1.351	1.352	1.173	1.225	1.216
(Million tons)		(19.4%)	(18.0%)	(18.1%)	(2.4%)	(7.0%)	(6.2%)
Generation (Gigawatt hours)							
- Oil	7237	4618	4469	4115	6598	4115	5703
		(-36.2%)	(-38.2%)	(-43.1%)	(-8.8%)	(-43.1%)	(-21.2%)
- Gas	1406	1782	1782	1271	1905	1152	1379
		(26.7%)	(26.7%)	(-9.6%)	(35.5%)	(-18.1%)	(-1.9%)
- Coal	66910	68378	65571	66437	63320	66557	64741
		(2.2%)	(-2.0%)	(-0.7%)	(-5.4%)	(-0.5%)	(-3.2%)
- Nuclear	27741	31480	31480	31480	31480	31480	31480
		(13.5%)	(13.5%)	(13.5%)	(13.5%)	(13.5%)	(13.5%)
- Hydro	122	112	112	112	112	112	112
		(-8.2%)	(-8.2%)	(-8.5%)	(-8.5%)	(-8.5%)	(-8.5%)
Total	103416	106370	103414	103415.	103415.	103415.	103415.

Table A.5 Emission and Generation Levels for Illinois

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions	1.048	1.213	1.232	1.233	1.149	1.149	1.149
(MM tons)		(15.7%)	(17.5%)	(17.6%)	(9.6%)	(9.6%)	(9.6%)
Generation (Gigawatt hours)							
- Oil	124	127	127	116	116	116	116
		(2.4%)	(2.4%)	(-6.7%)	(-6.7%)	(-6.7%)	(-6.7%)
- Gas	158	26	26	26.377	26.377	26.377	26.377
		(-83.5%)	(-83.5%)	(-83.3%)	(-83.3%)	(-83.3%)	(-83.3%)
- Coal	53883	52504	53568	53578	53578	53578	53578
		(-2.6%)	(-0.6%)	(-0.6%)	(-0.6%)	(-0.6%)	(-0.6%)
- Nuclear	0	0	0	0	0	0	0
		(0.0%)	(0.0%)	(0.0%)	(0.0%)	(0.0%)	(0.0%)
- Hydro	2939	3381	3381	3381	3381	3381	3381
		(15.0%)	(15.0%)	(15.0%)	(15.0%)	(15.0%)	(15.0%)
Total	571[illegible]4	56038	57102	57101.4	57101.4	57101.4	57101.4

Table A.6 Emission and Generation Levels for Kentucky

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions (Million tons)	0.968	0.992 (2.5%)	0.983 (1.5%)	0.981 (1.4%)	0.968 (0.0%)	0.969 (0.1%)	0.969 (0.1%)
Generation (Gigawatt hours)							
- Oil	408	21 (-94.9%)	21 (-94.9%)	21 (-94.8%)	21 (-94.8%)	21 (-94.8%)	21 (-94.8%)
- Gas	8	0 (-100.0%)	0 (-100.0%)	0 (-100.0%)	0 (-100.0%)	0 (-100.0%)	0 (-100.0%)
- Coal	69956	70855 (1.3%)	69956 (0.0%)	69958 (0.0%)	69958 (0.0%)	69958 (0.0%)	69958 (0.0%)
- Nuclear	0	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)
- Hydro	423	817 (93.1%)	817 (93.1%)	818 (93.3%)	818 (93.3%)	818 (93.3%)	818 (93.3%)
Total	70795	71693	70794	70796.7	70796.7	70796.7	70796.7

Table A.7 Emission and Generation Levels for West Virginia

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions	0.959	1.116	1.041	1.041	1.034	1.035	1.035
(Million tons)		(16.4%)	(8.6%)	(8.6%)	(7.8%)	(8.0%)	(8.0%)
Generation (Gigawatt hours)							
- Oil	198	1760	550	542	698	542	542
		(788.9%)	(177.8%)	(173.9%)	(252.5%)	(173.9%)	(173.9%)
- Gas	114	0	0	0	0	0	0
		(-100.0%)	(-100.0%)	(-100.0%)	(-100.0%)	(-100.0%)	(-100.0%)
- Coal	50618	54725	48274	48278	48123	48278	48278
		(8.1%)	(-4.6%)	(-4.6%)	(-4.9%)	(-4.6%)	(-4.6%)
- Nuclear	519	0	0	0	0	0	0
		(-100.0%)	(-100.0%)	(-100.0%)	(-100.0%)	(-100.0%)	(-100.0%)
- Hydro	8765	11389	11389	11390	11390	11390	11390
		(29.9%)	(29.9%)	(29.9%)	(29.9%)	(29.9%)	(29.9%)
Total	60214	67874	60213	60210.2	60210.2	60210.2	60210.2

Table A.8 Emission and Generation Levels for Tennessee

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions (Million tons)	0.759	0.888 (16.9%)	0.716 (-5.7%)	0.715 (-5.9%)	0.732 (-3.6%)	0.731 (-3.7%)	0.732 (-3.7%)
Generation (Gigawatt hours)							
- Oil	546	1110 (103.3%)	171 (-68.7%)	171 (-68.7%)	213 (-60.9%)	171 (-68.7%)	171 (-68.7%)
- Gas	287	351 (22.3%)	84 (-70.7%)	84 (-70.7%)	84 (-70.7%)	84 (-70.7%)	84 (-70.7%)
- Coal	49674	59790 (20.4%)	48631 (-2.1%)	48495 (-2.4%)	48453 (-2.5%)	48495 (-2.4%)	48495 (-2.4%)
- Nuclear	8436	8881 (5.3%)	8881 (5.3%)	9015 (6.9%)	9015 (6.9%)	9015 (6.9%)	9015 (6.9%)
- Hydro	4369	5545 (26.9%)	5545 (26.9%)	5545 (26.9%)	5545 (26.9%)	5545 (26.9%)	5545 (26.9%)
Total	63312	75677	63312	63310.6	63310.6	63310.6	63310.6

Table A.9 Emission and Generation Levels for Georgia

Minimum Capacity Factor Tests for 1980

	1980 Historical	Dec11 Basecase	Transfer Basecase	Validation Test	Test 1	Test 2	Test 3
Emissions (Million tons)	0.722	0.864 (19.7%)	0.849 (17.6%)	0.854 (18.3%)	0.764 (5.9%)	0.802 (11.1%)	0.802 (11.1%)
Generation (Gigawatt hour)							
- Oil	44352	42137 (-5.0%)	38257 (-13.7%)	37473 (-15.5%)	37135 (-16.3%)	32549 (-26.6%)	32549 (-26.6%)
- Gas	14860	14650 (-1.4%)	14650 (-1.4%)	15431 (3.8%)	16086 (8.3%)	20355 (37.0%)	20355 (37.0%)
- Coal	19737	25648 (29.9%)	25648 (29.9%)	25649 (30.0%)	25333 (28.4%)	25649 (30.0%)	25649 (30.0%)
- Nuclear	16737	17120 (2.3%)	17120 (2.3%)	17120 (2.3%)	17120 (2.3%)	17120 (2.3%)	17120 (2.3%)
- Hydro	215	224 (4.2%)	224 (4.2%)	226 (5.2%)	226 (5.2%)	226 (5.2%)	226 (5.2%)
Total	95901	99779	95899	95900.3	95900.3	95900.3	95900.3

Table A.10 Emission and Generation Levels for Florida

APPENDIX B ICF, INC. BASE CASE FORECAST

The Interim EPA Base Case Forecast memorandum from ICF, Inc. is included in its entirety. This memorandum describes the forecast used to compare the results of the Advanced Utility Simulation Model with the Coal and Electric Utilities Model using assumptions described in Appendix C. The comparison of these forecasts is provided in Chapter 5 of this report.

ICF INCORPORATED International Square, 1850 K Street, Northwest, Washington, D.C. 20006 (202) 862-1100

March 10, 1987

MEMORANDUM

TO: Paul Schwengels, EPA

FROM: Bruce Braine, ICF
Richard Stuebi

SUBJECT: Interim EPA Base Case Forecasts

This memorandum presents summary national and regional forecasts from the recently completed 1987 interim EPA Base Case. This base case was developed for use in the CEUM/AUSM comparison effort and for use in regulatory analyses prior to the development of the final EPA base.

This memorandum is divided into two sections. The first section briefly discusses the emission, generation, and coal production forecasts and trends. The second section notes the major differences between this interim 1987 EPA base and the 1985 EPA Base Case. Attachment A provides forecasts of utility SO2 and NOx emissions, emission rates, generation, fuel consumption, and coal production, while Attachment B presents detailed input specifications and assumptions for the preliminary 1987 EPA Base Case as compared to the previous 1985 EPA base.

INTERIM 1987 BASE CASE FORECASTS

Summary forecasts from the Interim Base Case are presented in Table 1. The findings indicate include:

- Sulfur dioxide emissions rise steadily throughout the forecast period, from 1985 "actual" levels of 16.3 million tons to an estimated 21.7 million tons by 2010. Most of this growth in the near term (1985-1995) is forecast to come from increased utilization of existing (pre-1986) coal fired plants and greater use of oil relative to gas at oil/gas steam units as gas prices firm relative to oil prices. After 2000, most growth will come from the addition of new coal fired powerplants.

- Utility sulfur dioxide emissions are forecast to increase by 2.3 million tons between 1985 and 1995, from 16.3 million tons to 18.6 million tons. This reflects:

  - A 1.5 million ton increase in emissions (from 15.7 million tons to 17.2 million tons) at existing (pre-1986) coal powerplants.

  - A 0.5 million ton increase in emissions (from 0.6 million tons to 1.1 million tons) from oil/gas units.

  - The addition of new coal-fired powerplants since 1985, which accounts for an estimated 0.2 million tons of sulfur dioxide by 1995.

- Higher emissions from existing coal plants in the near-term (1985-1995) are due to several factors. At present, a number of coal powerplants are being less-than-fully utilized primarily due to (1) excess coal capacity, associated with a large number of new coal-fired plants brought on-line during the 1980-85 period when there was relatively little electricity sales growth, (2) a large amount of new nuclear capacity recently brought on-line, which has also resulted in existing coal plants being utilized less, particularly in states such as Illinois, the Carolinas, and Pennsylvania. As electricity sales increase and the number of new nuclear and coal plants added begins to decline over this time frame, the coal capacity which is now relatively idle should be utilized more intensively.

- Higher emissions from oil/gas steam units will result from increased use of oil relative to gas as the gas "bubble" disappears and gas prices firm relative to oil prices.

- After 1995, sulfur dioxide emissions are expected to increase by an additional 3.1 million tons by 2010 (from 18.6 million tons to 21.7 million tons). This reflects:

  - An additional 1.5 million ton increase (from 17.2 million tons to 18.7 million tons) from existing coal powerplants by 2000 as existing plants are utilized more fully.

  - An increase of 1.8 million tons associated with the addition of new coal-fired units. Most of this increase occurs after 2000 when most of the new coal plants are built.

  - An 0.2 million ton decline (from 1.1 million tons to 0.9 million tons) at oil/gas plants as oil/steam plants are retired.

- New coal sulfur dioxide emissions increase dramatically in the long-term (1995-2010) because 223 additional gigawatts of new coal capacity is forecast to be completed over this time period. Most new coal capacity is forecast to be built after 2000 (198 gigawatts) and reflects:

  - Coal capacity built to meet higher electricity demands (142 gigawatts).
  - Capacity built to replace retiring nuclear, coal, and oil/gas steam plants (42 gigawatts).
  - Capacity built to replace oil/gas steam capacity which, as oil prices rise, becomes increasingly expensive to operate (14 gigawatts).

  As a result of these coal builds, coal generation accounts for slightly more than half of all energy generated in 1995, but represents two-thirds of total generation in 2010. However, because new scrubbed coal capacity continues to increase its share of total coal capacity, the average coal sulfur dioxide emission rate is forecast to fall steadily, particularly as the older SIP units begin to retire with more frequency. Thus, coal SO2 emissions do not increase as rapidly as coal fired generation.

- Utility nitrogen oxide emissions are also forecast to rise significantly from 1980 to 2010. Moreover, total utility nitrogen oxide emissions are forecast to rise more quickly than sulfur dioxide emissions, especially between 2000 and 2010. While the average nitrogen oxide emission rate does decrease over time, it falls less significantly than the average sulfur dioxide emissions rate. This is because average NOx rates at existing units are only somewhat higher than new plant NOx limits, but SO2 rates at existing units are substantially higher than new plant SO2 rates. Therefore, nitrogen oxide emissions rise roughly in parallel with increases in coal and oil/gas generation, increasing from 1980 historical levels of 6.6 million tons to 11.3 million tons in 2010.

- Electricity generation is expected to grow at roughly the same rate as electricity sales. Both grow at roughly 2.2 percent annually through 1995, and 2.0 percent per year thereafter. Nuclear generation accounts for most of this growth through 1990, increasing by 60 percent (from 380 to 610 billion

TABLE 1

NATIONAL SUMMARY BASE CASE FORECASTS

	1980	1985	1990	1995	2000	2010
SO2 Emissions (millions of tons)						
Coal						
Existing[1]	16.02	15.69	16.78	17.23	17.87	18.74
New	-	-	0.10	0.20	0.43	2.01
Total	16.02	15.69	16.88	17.43	18.30	20.26
Oil/Gas	1.36	0.58	0.89	1.14	1.32	0.93
Total	17.38	16.27	17.77	18.57	19.62	21.69
NOx Emissions (millions of tons)						
Coal						
Existing[1]	5.44	NA	6.53	6.82	7.14	7.26
New	-	NA	0.16	0.26	0.65	3.52
Total	5.44	NA	6.70	7.08	7.79	10.77
Oil/Gas	1.18	NA	0.47	0.77	0.84	0.52
Total	6.62	NA	7.16	7.85	8.63	11.29
Utility Electricity Generation (trillions of kwh)						
Coal	1.16	1.40	1.50	1.58	1.78	2.79
Oil/Gas	0.59	0.39	0.22	0.38	0.44	0.29
Nuclear	0.25	0.38	0.61	0.62	0.62	0.46
Hydro & Other	0.28	0.30	0.41	0.48	0.53	0.58
Total	2.28	2.47	2.74	3.06	3.37	4.12
Coal Production (millions of tons)						
Northern Appalachia	185.1	161.5	174.4	179.9	187.8	258.0
Central Appalachia	232.8	244.8	244.3	282.4	330.4	406.9
Southern Appalachia	26.4	25.6	25.5	22.5	24.6	35.8
Midwest	134.4	133.3	130.8	124.8	142.6	175.0
West	251.0	315.9	389.6	428.3	479.2	777.2
Total	829.7	881.1	964.6	1037.9	1164.6	1652.9

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[1] "Existing" capacity defined as coal capacity which came on line prior to 12/31/85.

NA: Not Available.

kilowatt-hours) due to the many new nuclear units assumed to be brought on-line, as well as several others (notably, the TVA nuclear units) that are expected to be restarted. Oil/gas generation declines significantly as oil and gas prices rise from low levels in 1986, more nuclear plants are brought on-line, and excess coal capacity is used to displace more expensive oil/gas generation. As mentioned previously, coal generation rises steadily through 2010, as underutilized existing capacity is utilized more and new coal capacity is added. After 2000, coal generation jumps significantly (by about 57 percent) by 2010 to compensate for nuclear and oil/gas retirements and to meet higher sales demands.

- National coal production is forecast to increase in line with the growth in coal-fired generation, reflecting the high percentage of coal shipments that go to the utility sector (about 79 percent in 1985). Regional coal production growth varies considerably. For example, in two key producing areas:
    - Demand for coals from higher sulfur producing regions, such as the Midwest, is expected to remain approximately flat until 2000. This reflects the combination of several factors: (1) shifts away from Midwestern coals associated with tighter emission limits in Wisconsin and more economic use of Western coals in states such as Missouri, (2) a large amount of nuclear capacity built in regions using predominantly Midwestern coals (e.g., Illinois), and (3) some increases in demand in growing markets which burn Midwest coals such as Indiana and Kentucky. Until new scrubbed plants get built, mainly after 2000, there is relatively little growth in demand expected for these coals.
    - Coals from the West are forecast to experience a very high rate of demand growth, reflecting primarily (1) penetration into Midwestern markets such as Wisconsin and Missouri, and (2) growth in new coal capacity which is concentrated in the Western states and which will therefore be supplied by western coals.

COMPARISON OF THE INTERIM 1987 BASE WITH THE 1985 BASE

Table 2 compares the key 1995 forecasts from the interim 1987 EPA Base Case analysis with those developed for the previous 1985 EPA Base Case. Table 3 on pages 8 and 9 presents a comparison of major input assumptions for 1995 used in both base cases.

TABLE 2

COMPARISON OF INTERIM 1987 BASE FORECASTS WITH 1985 BASE FORECASTS - 1995

	Interim 1987 Base	1985 Base	Difference
SO2 Emissions (millions of tons)	18.6	19.7	-1.1
NOx Emissions (millions of tons)	7.8	8.4	-0.6
SO2 Emissions Rate (lbs. SO2 per MMBtu)	1.79	1.74	+0.05
NOx Emissions Rate (lbs. SO2 per MMBtu)	0.76	0.75	+0.01
Utility Electricity Generation (trillions of kwh)			
Coal	1.58	1.71	-0.13
Oil/Gas	0.38	0.43	-0.05
Nuclear	0.62	0.64	-0.02
Hydro & Other	0.48	0.38	+0.10
Total	3.06	3.16	-0.10
Coal Production (millions of Tons)			
Northern Appalachia	179.9	197.5	-17.6
Central Appalachia	282.4	306.6	-24.2
Southern Appalachia	22.5	25.1	-2.6
Midwest	124.8	150.5	-25.7
West	428.3	516.0	-87.7
Total	1037.9	1195.7	-157.8

Some of the key forecast differences are noted below:

- Sulfur dioxide emissions are lower in the more recent Base Case. This is primarily due to lower coal-fired generation (mostly because total generation and sales are lower and contributions from cogeneration and renewable sources are higher).

- Nitrogen oxide emissions are also forecast to be lower in the new case, largely as a result of lower fossil-fuel generation.

- Generation is lower due to lower assumed growth in electricity sales (2.2 percent per year through 1995 compared to 2.5 percent in the previous EPA base). Both coal and oil/gas generation fall proportionally more than total generation requirements because nuclear is relatively unchanged and cogeneration and renewables (such as municipal waste, small hydro, and geothermal) have increased significantly from the previous EPA base.

- Coal production is lower as a result of lower coal fired generation. Midwest and Western coals are reduced the most because these coals are generally burned in newer plants, and fewer new plants are built by 1995.

TABLE 3

COMPARISON OF MAJOR BASE CASE ASSUMPTIONS - 1995

	Interim 1987 Base	1985 Base	Comments
U.S. Electricity Sales (trillions of kwh)	2.86	2.97	Lower sales results a 2.2 percent per year growth rate vs. a 2.5 percent in the previous base.
Imports of Canadian Electricity (billions of kwh)	64	90	Lower imports reflect recent ICF assessments of transmission capabilities and available capacity in Canada.
World Oil Price (early 1986 $/bbl)	23.60	35.10	Lower oil prices reflect the large decline in oil prices which occurred since the development of the 1985 Base Case.
Coal Reconversions (Gw) 1986-1995	1.2	6.4	Fewer reconversions reflect recent cancellations largely associated with lower oil prices.
Cogeneration & Other Renewables (billions of kwh)	185	90	More cogeneration and other Q.Fs based on continuing ICF assessments of the markets.
Non-Utility Coal Demand (millions of tons)	204	306	Lower non-utility demand largely reflects lower forecasted industrial demand primarily due to lower oil and gas prices reducing the number of new coal boilers and coal conversions.
Emission Regulations (lbs. SO2/MMBtu)			
Wisconsin coal plants:			Tighter limits in Wisconsin reflect finalization of SIP regulations. Cumberland limit changed due to information obtained from TVA.
Alma #1-5	1/	4.00	
Columbia #1	2.12	4.00	
Dewey #1-2	1/	4.78	
Genoa #6	1/	4.00	
Oak Creek #1-8	3.20	4.00	
Rock River #1-2	3.20	4.00	

TABLE 3 (Continued)

COMPARISON OF MAJOR BASE CASE ASSUMPTIONS - 1995

	Interim 1987 Base	1985 Base	Comments
Emission Regulations (Continued)			
Burger #1-5 (Ohio Edison)	9.02	No Limit	
Cumberland #1-2 (TVA)	5.00	4.20	

1/ These units burn both bituminous and subbituminous coals. The bituminous is limited to 3.86 lbs. SO2/MMBtu, while the subbituminous is limited to 1.66 lbs. SO2/MMBtu.

ATTACHMENT A

FORECASTS FROM THE INTERIM 1987 EPA BASE CASE

1990-2010

TABLE A-1

UTILITY SULFUR DIOXIDE EMISSION FORECASTS

			EPA Base Case			
	1980	1985	1990	1995	2000	2010
Utility SO2 Emissions (millions of tons)						
31-Eastern States						
Coal						
Existing[1/]	14.92	14.21	14.88	15.26	15.85	16.76
New - NSPS	-	-	0.05	0.13	0.20	0.20
New - ANSPS	-	-	0.01	0.01	0.14	1.27
Total	14.92	14.21	14.94	15.41	16.20	18.23
Oil/Gas	1.27	0.57	0.77	1.02	1.19	0.82
Total 31-Eastern States	16.19	14.78	15.71	16.43	17.39	19.05
17-Western States						
Coal						
Existing[1/]	1.10	1.48	1.92	2.00	2.05	2.01
New - NSPS	-	-	0.02	0.02	0.02	0.02
New - ANSPS	-	-	0.02	0.02	0.06	0.53
Total	1.10	1.48	1.96	2.05	2.13	2.56
Oil/Gas	0.09	0.01	0.12	0.12	0.13	0.11
Total 17-Eastern States	1.19	1.49	2.08	2.17	2.26	2.67
Total U.S.						
Coal						
Existing[1/]	16.02	15.69	16.80	17.26	17.90	18.77
New - NSPS	-	-	0.07	0.16	0.22	0.22
New - ANSPS	-	-	0.03	0.04	0.21	1.79
Total	16.02	15.69	16.90	17.46	18.33	20.79
Oil/Gas	1.36	0.58	0.89	1.14	1.32	0.93
Total U.S.	17.38	16.27	17.79	18.60	19.65	21.72

[1/] Designated existing capacity as of 12/31/85. Represents emissions from all existing coal capacity, including emissions from NSPS and ANSPS units.

TABLE A-2

UTILITY SULFUR DIOXIDE EMISSION RATE FORECASTS

	1980	1985	EPA Base Case			
			1990	1995	2000	2010
Utility SO2 Emission Rates						
(lbs. SO2/MMBtu)						
31-Eastern States						
Coal						
Existing[1]	3.13	2.57	2.62	2.56	2.52	2.60
New - NSPS	-	-	0.99	0.85	0.88	0.95
New - ANSPS	-	-	0.35	0.31	0.33	0.35
Total	3.13	2.57	2.60	2.50	2.33	1.77
Oil/Gas	0.85	0.62	1.50	0.95	0.96	0.86
Total 31-Eastern States	2.58	2.25	2.51	2.27	2.12	1.69
17-Western States						
Coal						
Existing[1]	0.85	0.83	0.97	0.98	0.98	0.99
New - NSPS	-	-	0.46	0.46	0.46	0.46
New - ANSPS	-	-	0.17	0.20	0.19	0.25
Total	0.85	0.83	0.92	0.92	0.86	0.61
Oil/Gas	0.06	0.01	0.20	0.13	0.13	0.18
Total 17-Eastern States	0.42	0.53	0.76	0.69	0.65	0.56
Total U.S.						
Coal						
Existing[1]	2.64	2.15	2.19	2.15	2.14	2.21
New - NSPS	-	-	0.72	0.76	0.81	0.86
New - ANSPS	-	-	0.21	0.23	0.27	0.31
Total	2.64	2.15	2.14	2.08	1.95	1.44
Oil/Gas	0.45	0.28	0.79	0.58	0.58	0.60
Total U.S.	1.90	1.73	1.97	1.79	1.68	1.35

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[1] Designated existing capacity as of 12/31/85. Represents emissions from all existing coal capacity, including emissions from NSPS and ANSPS units.

TABLE A-3

UTILITY NITROGEN OXIDE EMISSION FORECASTS [1]

	1980	EPA Base Case			
		1990	1995	2000	2010
Utility NOx Emissions (millions of tons)					
31-Eastern States					
Coal					
Existing[2]	4.55	5.12	5.36	5.66	5.81
New - NSPS	-	0.04	0.11	0.16	0.15
New - ANSPS	-	0.02	0.03	0.26	2.10
Total	4.55	5.18	5.50	6.08	8.06
Oil/Gas	0.57	0.19	0.42	0.43	0.29
Total 31-Eastern States	5.12	5.37	5.91	6.51	8.36
17-Western States					
Coal					
Existing[2]	0.89	1.41	1.46	1.49	1.45
New - NSPS	-	0.04	0.04	0.04	0.04
New - ANSPS	-	0.07	0.08	0.19	1.23
Total	0.89	1.52	1.58	1.71	2.71
Oil/Gas	0.61	0.27	0.36	0.41	0.22
Total 17-Eastern States	1.50	1.79	1.93	2.12	2.93
Total U.S.					
Coal					
Existing[2]	5.44	6.53	6.82	7.14	7.26
New - NSPS	-	0.07	0.15	0.20	0.19
New - ANSPS	-	0.09	0.11	0.45	3.33
Total	5.44	6.70	7.08	7.79	10.77
Oil/Gas	1.18	0.47	0.77	0.84	0.52
Total U.S.	6.62	7.16	7.85	8.63	11.29

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[1] Data for 1985 not available.

[2] Designated existing capacity as of 12/31/85. Represents emissions from all existing coal capacity, including emissions from NSPS and ANSPS units.

TABLE A-4

UTILITY NITROGEN OXIDE EMISSION RATE FORECASTS

		EPA Base Case			
	1980	1990	1995	2000	2010
Utility NOx Emission Rates					
(lbs. NOx/MMBtu)					
31-Eastern States					
Coal					
Existing[2J]	0.96	0.90	0.90	0.90	0.90
New - NSPS	-	0.75	0.71	0.71	0.71
New - ANSPS	-	0.60	0.60	0.60	0.58
Total	0.96	0.90	0.89	0.87	0.78
Oil/Gas	0.38	0.38	0.39	0.34	0.31
Total 31-Eastern States	0.82	0.86	0.82	0.79	0.74
17-Western States					
Coal					
Existing[2J]	0.69	0.71	0.71	0.71	0.71
New - NSPS	-	0.75	0.75	0.75	0.75
New - ANSPS	-	0.64	0.66	0.57	0.58
Total	0.69	0.71	0.71	0.69	0.65
Oil/Gas	0.40	0.45	0.40	0.39	0.38
Total 17-Eastern States	0.53	0.65	0.62	0.61	0.61
Total U.S.					
Coal					
Existing[2J]	0.90	0.85	0.85	0.85	0.86
New - NSPS	-	0.75	0.72	0.72	0.72
New - ANSPS	-	0.63	0.64	0.59	0.58
Total	0.90	0.85	0.84	0.83	0.74
Oil/Gas	0.39	0.42	0.39	0.37	0.33
Total U.S.	0.73	0.79	0.76	0.74	0.70

[1J] Data for 1985 not available.

[2J] Designated existing capacity as of 12/31/85. Represents emissions from all existing coal capacity, including emissions from NSPS and ANSPS units.

TABLE A-5

TOTAL UTILITY POWERPLANT CAPACITY
(Gigawatts)

	1980	1985	EPA Base Case 1990	 1995	 2000	 2010
Coal						
Existing[1]	245.7	286.7	287.8	287.8	287.6	282.7
New - NSPS	-	-	3.4	7.0	9.4	9.4
New - ANSPS	-	-	5.0	5.9	28.2	225.9
Total	245.7	286.7	296.1	300.7	325.2	518.0
Oil/Gas Steam	166.4[2]	205.2[2]	149.0	149.0	148.9	139.7
Oil/Gas Turbine & Combined Cycle			54.4	55.0	64.1	75.5
Nuclear	56.5	75.7	103.2	106.4	106.2	78.2
Hydro & Other	76.3	83.6	108.3	116.6	124.5	132.8
Total	542.8	651.2	711.0	727.6	768.9	944.2

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[1] Designated existing capacity as of 12/31/85. Represents total existing coal capacity, including NSPS and ANSPS units. Existing coal capacity increases between 1985 and 1990 due to reconversions of oil capacity to coal.

[2] Represents total oil/gas capacity, including oil/gas turbines and combined cycle capacity.

TABLE A-6

TOTAL UTILITY ELECTRICITY GENERATION
(Trillion Kwh)

	1980	1985	EPA Base Case 1990	1995	2000	2010
Coal						
Existing[1]	1.16	1.40	1.45	1.51	1.57	1.59
New - NSPS	-	-	0.02	0.04	0.05	0.05
New - ANSPS	-	-	0.03	0.03	0.15	1.14
Total	1.16	1.40	1.50	1.58	1.78	2.79
Oil/Gas Steam	0.59[2]	0.39[2]	0.19	0.34	0.38	0.21
Oil/Gas Turbine & Combined Cycle			0.03	0.04	0.06	0.08
Nuclear	0.25	0.38	0.61	0.62	0.62	0.46
Hydro & Other	0.28	0.30	0.41	0.48	0.53	0.58
Total	2.28	2.47	2.74	3.06	3.37	4.12

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[1] Designated existing capacity as of 12/31/85. Represents total existing coal capacity generation, including NSPS and ANSPS unit generation.

[2] Represents total oil/gas capacity generation, including oil/gas turbine and combined cycle generation.

TABLE A-7

UTILITY FUEL CONSUMPTION FORECASTS
(Quads)

			EPA Base Case			
Utility Fuel Consumption	1980	1985	1990	1995	2000	2010
31-Eastern States						
Coal						
Low Sulfur	0.87	1.89	2.13	2.63	3.35	6.82
Low-Medium Sulfur	1.61	1.56	2.03	2.08	2.65	3.82
High-Medium Sulfur	3.18	3.66	3.51	3.82	3.78	4.86
High Sulfur	3.86	3.90	3.85	3.81	4.11	5.08
Total	9.53	11.01	11.51	12.34	13.90	20.57
Oil	1.99	0.93	1.03	1.54	1.98	1.79
Gas	1.01	0.92	0.18	0.79	0.71	0.44
17-Western States						
Coal						
Low Sulfur	1.41	1.61	2.36	2.42	2.71	5.56
Low-Medium Sulfur	0.43	0.94	0.80	0.85	0.95	1.55
High-Medium Sulfur	0.74	0.96	1.06	1.11	1.22	1.21
High Sulfur	0.01	0.07	0.06	0.07	0.06	0.08
Total	2.59	3.58	4.28	4.44	4.93	8.40
Oil	0.48	0.06	0.23	0.24	0.28	0.34
Gas	2.58	2.28	1.07	1.64	1.90	0.99
Total U.S.						
Coal						
Low Sulfur	2.28	3.50	4.50	5.06	6.06	12.38
Low-Medium Sulfur	2.04	2.49	2.83	2.93	3.60	5.37
High-Medium Sulfur	3.92	4.62	4.57	4.94	4.99	6.06
High Sulfur	3.87	3.97	3.91	3.87	4.18	5.16
Total	12.12	14.58	15.80	16.79	18.84	28.96
Oil	2.47	0.99	1.26	1.79	2.26	2.13
Gas	3.59	3.20	1.25	2.43	2.61	1.44

TABLE A-8

COAL PRODUCTION AND SHIPMENT FORECASTS
(Millions of Tons)

			EPA Base Case			
	1980	1985	1990	1995	2000	2010
Coal Production						
Northern Appalachia	185.1	165.5	174.4	179.9	187.8	258.0
Central Appalachia	232.8	244.8	244.3	282.4	330.4	406.9
Southern Appalachia	26.4	25.6	25.5	22.5	24.6	35.8
Midwest	134.4	133.3	130.8	124.8	142.6	175.0
West	251.0	315.9	389.6	428.3	479.2	777.2
Total U.S.	829.7	881.1	964.6	1037.9	1164.6	1652.9
Coal Transportation						
Western Coal Shipped East	36.7	32.2	44.0	54.7	69.6	183.3
Eastern Coal Shipped West	25.0	30.0	24.9	30.6	38.3	42.3
Coal Production by State						
Northern Appalachia						
Pennsylvania	93.1	65.3	70.2	74.2	86.7	133.7
Ohio	39.4	35.7	38.2	33.5	32.5	37.2
Maryland	3.8	2.8	3.6	3.0	2.5	1.9
No. W. Virginia	48.8	56.9	62.4	69.1	66.1	85.1
Total	185.1	161.5	174.4	179.9	187.8	258.0
Central Appalachia						
So. W. Virginia	72.7	70.7	83.2	92.6	134.0	188.0
Virginia	41.0	43.9	45.9	51.2	68.7	69.6
East Kentucky	109.2	121.7	108.7	130.7	114.0	126.5
Tennessee	9.9	7.5	6.5	7.9	13.8	22.9
Total	232.8	244.8	244.3	282.4	330.4	406.9
Midwest						
Illinois	62.5	61.1	58.4	58.1	82.0	100.5
Indiana	30.9	34.0	31.4	25.9	21.4	27.4
West Kentucky	41.0	38.2	40.9	40.8	39.3	47.2
Total	134.4	133.3	130.8	124.8	142.6	175.0

TABLE A-9

UTILITY SO2 EMISSIONS BY REGION
(Thousands of Tons)

			EPA Base Case			
Region	1980	1985	1990	1995	2000	2010
Maine/Vt/NH	97	86	55	70	70	81
Mass/Conn/Rhode Island	292	288	270	289	336	376
New York	479	420	369	481	518	543
Pennsylvania	1422	1320	1152	1275	1186	1232
New Jersey	103	97	96	130	127	191
Maryland/Delaware	277	281	311	378	396	409
Virginia	157	131	195	240	293	341
West Virginia	984	969	1002	961	1007	1037
N. & S. Carolina	655	500	660	689	728	968
Georgia	704	976	864	874	946	1021
Florida	692	501	898	937	968	910
Ohio	2185	2193	2710	2572	2677	2849
Michigan	608	401	429	449	477	516
Illinois	1110	1054	831	955	1096	1407
Indiana	1672	1498	1668	1710	1782	2007
Wisconsin	488	367	333	273	267	327
Kentucky	1029	745	869	893	935	941
Tennessee	910	802	875	856	922	1056
Alabama	535	563	444	512	565	595
Mississippi	122	113	140	146	153	168
Minnesota	160	124	145	169	218	216
Iowa	236	219	213	302	368	438
Missouri	1227	997	973	1058	1118	1196
Arkansas	27	69	123	125	151	131
Louisiana	21	67	88	86	84	89
Total 31-Eastern States	16,193	14,781	15,712	16,431	17,387	19,047

TABLE A-9 (Continued)

UTILITY SO2 EMISSIONS BY REGION
(Thousands of Tons)

			EPA Base Case			
Region	1980	1985	1990	1995	2000	2010
N. & S. Dakota	109	156	219	227	239	302
Kansas/Nebraska	149	211	304	340	351	365
Oklahoma	45	80	218	209	225	225
Texas	295	430	651	695	710	890
Montana	23	22	45	45	48	64
Wyoming	128	135	63	62	70	68
Idaho	-	-	-	-	-	-
Colorado	71	84	127	130	137	145
New Mexico	78	114	56	56	56	57
Utah	25	27	67	69	70	77
Arizona	84	104	124	126	130	138
Nevada	38	35	75	76	79	78
Washington/Oregon	72	88	132	130	149	237
California	70	3	-	-	-	20
Total 17-Western States	1,187	1,489	2,081	2,166	2,263	2,668
Total U.S.	17,380	16,270	17,793	18,597	19,650	21,715

Note: Totals may not add due to independent rounding.

TABLE A-10

UTILITY NOX EMISSIONS BY REGION [1]
(Thousands of Tons)

Region	1980	EPA Base Case			
		1990	1995	2000	2010
Maine/Vt/NH	32	25	32	31	49
Mass/Conn/Rhode Island	81	94	110	125	263
New York	146	127	173	221	376
Pennsylvania	417	370	420	384	393
New Jersey	81	53	90	100	202
Maryland/Delaware	91	116	134	150	227
Virginia	66	79	96	137	225
West Virginia	319	371	353	376	383
N. & S. Carolina	352	331	342	407	608
Georgia	235	234	249	268	343
Florida	242	306	328	395	462
Ohio	526	618	612	639	790
Michigan	262	292	303	333	436
Illinois	396	277	327	392	612
Indiana	411	451	515	530	566
Wisconsin	132	152	174	191	248
Kentucky	278	353	372	413	416
Tennessee	215	241	240	256	478
Alabama	188	173	196	234	253
Mississippi	57	52	53	56	105
Minnesota	98	112	130	155	136
Iowa	92	101	111	131	161
Missouri	270	287	321	334	384
Arkansas	26	80	81	91	89
Louisiana	98	79	150	158	153
Total 31-Eastern States	5,116	5,374	5,914	6,505	8,358

TABLE A-10 (Continued)

UTILITY NOX EMISSIONS BY REGION [1]
(Thousands of Tons)

Region	1980	EPA Base Case			
		1990	1995	2000	2010
N. & S. Dakota	77	121	126	134	257
Kansas/Nebraska	140	194	218	219	215
Oklahoma	127	142	142	153	207
Texas	544	580	655	720	970
Montana	20	55	55	71	76
Wyoming	96	136	136	158	157
Idaho	-	-	-	-	-
Colorado	98	136	137	146	176
New Mexico	75	80	81	80	83
Utah	40	98	98	99	132
Arizona	89	113	117	127	168
Nevada	42	67	68	79	91
Washington/Oregon	29	45	46	76	247
California	132	23	57	61	154
Total 17-Western States	1,505	1,790	1,935	2,122	2,933
Total U.S.	6,621	7,164	7,849	8,628	11,291

Note: Totals may not add due to independent rounding.

[1] 1985 data not available.

ATTACHMENT B

MAJOR ASSUMPTIONS IN THE INTERIM 1987 EPA BASE CASE

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
ELECTRIC UTILITY ENERGY DEMAND			
o World Oil Prices (early 1986 $/bbl)			
1990	17.80	30.10	New case reflects latest ICF analyses and assumes modest real increase in oil prices through 1990 and 3 percent per year growth in the long term.
1995	23.60	35.10	
2000	27.40	40.10	
2010	36.80	51.30	
o Electricity Growth (% Per Year)			
1986-1995	2.2	2.5	New case reflects EPA assumptions.
1995-2010	2.0	2.5	
o Total U.S. Nuclear Capacity (Gw)			
1990	103	105	Capacity in proposed case is now lower due to some nuclear postponements and cancellations and reflecting the TVA nuclear plant shut downs. In 2010, no new nuclear plants are built to replace retirements.
1995	106	108	
2000	106	109	
2010	79	120	
o Nuclear Capacity Factors (%)			
1985	61	60	
1990	67	64	
1995	67	67	
2000	67	67	
2010	67	67	
o Substitution of Coal for Oil and Gas (Gw)			
Reconversions 1986-1995	1.2	6.4	The new case reflects most recent cancellations.
o Utility Capital Costs (1986 $/kw)			
Coal	900-1,010	990-1,175	Costs no longer include 10% real escalation. Powerplant costs shown here do not include charges for transmission hookup.
Nuclear	1,725-1,960	1,898-2,156	
Turbine	275- 315	302- 346	
Dry Scrubbers, New	99- 112	109- 123	
Wet Scrubbers, New	204- 245	224- 269	

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES
(Continued)

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
ELECTRIC UTILITY ENERGY DEMAND (Continued)			
o Powerplant Lifetime (Years)			
Coal Steam	60	60	Coal and oil/gas steam powerplants are refurbished after 30 years for $200/kw (early 1986 $). This is assumed to extend their useful lifetime from 45 to 60 years. Reconversions are assumed to retire 30 years after their reconversion date.
Oil/Gas Steam	60	45	
Nuclear	35	35	
Oil/Gas Turbine	20	20	
o Coal Powerplant Heat Rates Over Time	0.25% per year increase over current levels. After refurbishment, heat rates are improved (decreased) by five percent.	SAME	Based on empirical studies and engineering assessments of heat rate deterioration over time and the effects of powerplant refurbishment.
o Minimum Turndown Rates	Coal :35% Oil/Gas Steam:20%	SAME	Coal and oil/gas steam units must operate at or above minimum load.
o Cogeneration (bkwh)	1990 = 85 1995 = 117 2000 = 154 2010 = 194	1990 = 77 1995 = 99 2000 = 125 2010 = 149	Latest ICF analysis of cogeneration facilities are used in the new case.
o Canadian Power Imports (bkwh)			
1990	68	69	The new case reflects latest ICF analyses.
1995	64	90	
2000	76	87	
2010	75	97	

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES
(Continued)

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
NON-UTILITY COAL DEMAND			
o Industrial/Retail Coal Use (millions of tons)	1990 = 87 1995 = 91 2000 = 98 2010 = 137	1990 = 109 1995 = 135 2000 = 170 2010 = 220	Latest forecast of ICF Industribl Boiler Model (IBM) combined with latest ICF forecast of the kiln and residential/commercial coal markets. Lower numbers reflect effects of lower oil and gas price forecasts. After 1990, large industrial boilers (greater than 100 MMBtu/hr) are assumed to be required to scrub.
o Coal Exports (millions of tons)			
-- Steam Coal	1990 = 24 1995 = 32 2000 = 35 2010 = 35	1990 = 25 1995 = 48 2000 = 69 2010 = 120	Latest ICF forecasts are used in the new case.
-- Metallurgical Coal Exports	1985 = 56 1990 = 49 1995 = 45 2000 = 40 2010 = 30	1985 = 53 1990 = 49 1995 = 53 2000 = 61 2010 = 65	Latest ICF forecasts are used in the new case.
o Domestic Metallurgical Coal Use (millions of tons)	1985 = 45 1990 = 37 1995 = 35 2000 = 32 2010 = 29	1985 = 54 1990 = 61 1995 = 62 2000 = 62 2010 = 62	Continuing trends in steel substitution limit forecasted domestic metallurgical coal use through most of the 1980s. Import reductions programs are now assumed to have less effect.
o Synthetics (Coal Input in millions of tons)	1990 = 6 1995 = 1 2000 = 1 2010 = 1	1990 = 8 1995 = 8 2000 = 8 2010 = 8	Outlook for coal-based projects continues to be unfavorable. Current forecast includes continued operation of the Great Plains gasification plant through 1990.
COAL SUPPLY PARAMETERS			
o Coal Transportation Rates (% Annual Real Escalation)			
-- Rail	Long-run marginal costs based on engineering	1981-1985 = -5.0% 1986-2000 = 0.0%	We have lowered our estimates of rail costs based on analysis of engineering and other cost data.

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES
(Continued)

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
COAL SUPPLY PARAMETERS (Continued)			
-- Truck; Barge	Long-run marginal costs based on engineering analysis	1981-1985 = 5.0% 1986-2000 = 0.0%	
o Mining Costs (% Annual Real Escalation)	Capital = 0.0% Labor 1984-1987 = 1984 Contracts 1987-on = 2% per year Materials = 0.0% Deep Productivity = 3% Surface Productivity = 2%	Capital = 1.0% Labor 1984-1987 = 1.0% 1987-on = 2.0% Materials = 0.0% Productivity = 1-2%	Labor rates until 1987 reflect 1984 contract. Real escalation depends upon inflation. Deep mine productivity now assumed to increase at 3% per year in new case.
OTHER GOVERNMENTAL REGULATIONS			
o Federal Leasing Policy	Enough	Enough	Federal leasing is assumed to be sufficient to avoid artificially driving up market prices.
o Air Pollution Regulations	Most recent federal and state rules, including proposed changes in state SIPs and state acid rain programs. No changes in limits associated with tall stack regulations. Large industrial boilers must scrub by 1990.	Most recent federal and state rules. SO_2 emission limits assumed to be tightened in New and Wisconsin over the next ten years.	

COMPARISON OF KEY INPUT ASSUMPTIONS FOR NEW AND PREVIOUS EPA BASE CASES
(Continued)

Critical Parameter	Interim 1987 EPA Base Case	1985 EPA Base Case	Comments
FINANCIAL PARAMETERS			
o Tax Depreciation Life (years)			Tax depreciation based on ACRS of 1981 ERTA for 1985 EPA Base Case. New tax act requires 150% declining balance depreciation and results in removal of the five year rapid write-off provision for retrofit pollution control.
Retrofit Pollution Control	15	5	
Others	15	15	
o Real Discount Rates (% Per Year)	Coal Mine = 6.00% Utility = 4.27%	SAME	
o Real Capital Charge Rates			New charge rates are higher under the new tax law due to the elimination of the Investment Tax Credit and changes in tax depreciation which slightly offset the impacts of a lower tax rate.
Coal/Nuclear/Combined Cycle	9.4%	9.0%	
New Scrubbers/Particulate Equipment	9.4%	9.0%	
Combustion Turbines	11.3%	10.5%	
Retrofit Scrubbers	9.0%	6.5%	
o Book Life (years)			
Coal/Nuclear/Combined Cycle	30	SAME	
Combustion Turbine	20		
Pollution Control-Retrofit	30		
Pollution Control-New	30		
o Input Year Dollars	Early 1986	Early 1980	
o Output Year Dollars	Mid 1987	Early 1985	
o Escalation Input to Output Dollars	1.045	1.34	

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November 4, 1986

MEMORANDUM

TO: Paul Schwengels, EPA
Larry Jones, EPA
Ron Capone, SAIC

FROM: Bruce Braine, ICF
Richard Stuebi, ICF

SUBJECT: Summary State-Level Assumptions and Specifications for the EPA Base Case

---

This memorandum presents summary state level assumptions for the EPA base case. These assumptions are to be used in setting up a series of AUSM (Advanced Utility Simulation Model) and CEUM (Coal and Electric Utility Model) comparison runs. Based on Ron Capone's and my earlier memoranda, the assumptions were developed at the state level in line with the level of aggregation of AUSM and similar to the level of aggregation in CEUM (although some CEUM demand regions are parts of states such as Ohio North and Ohio South, and some demand regions are combinations of states such as the Carolinas). Further, the assumptions are broken down into six basic areas as noted in these memoranda: (1) Electricity Demand (2) Electricity Supply (3) Utility Powerplant Operation and Costs (4) Financial Assumptions (5) Environmental Regulations and (6) Coal Reserve Assumptions.

Please note that these assumptions are for the EPA base case which was specified by EPA and developed about two years ago. As we have discussed, a number of these assumptions (such as world oil prices) would likely be different if a new base case were developed as this time. However, for comparability with recent analyses conducted by ICF for EPA, the current EPA base case was used.

We have provided all the data at the state level and for the forecast years 1990, 1995, 2000 and 2010. For some areas, such as coal and oil/gas plants, assumptions are provided only for 1985 (and some incremental builds between 1985 and 1990) since as part of the respective models' decision making criteria, additional builds will be forecasted.

The base case assumptions are presented in the following tables:

Electricity Demand

- Table 1 projects electricity sales in billions of kilowatt hours. This includes all final demands for electricity including that produced and sold to the grid by means of cogeneration but excluding self generation.

- Table 1(a) presents state-by-state load curve assumptions (i.e., required reserve margins, load factors, and average system capacity factors.)

Electricity Supply

- Table 2 presents forecasts of cogeneration in billions of kilowatt-hours. These numbers include all output from qualifying cogeneration facilities (e.g., fossil fuel cogenerators, small hydro and renewables).
- Table 3 provides forecasts of electricity imports as received from Canada in billions of kilowatt-hours.
- Table 4 and 5 shows total existing and new nuclear capacity estimates and forecasted nuclear capacity factors, respectively.
- Table 6, 7, and 8 present total utility coal capacity (in net dependable megawatts). Table 6 presents total existing coal capacity as of 1985 (in megawatts), while Table 7 indicates firm scheduled coal capacity added to the utility system between 1986 and 1990 (i.e., capacity that is assumed to be brought on-line regardless of load requirements). Table 8 shows estimated conversions of oil or gas powerplants to coal between 1986 and 1990.
- Tables 9-11 present existing generating capacity (in net dependable megawatts, as of December 31, 1985) for oil/gas steam, turbine, and combined cycle plants, respectively.
- Table 12 provides total capacity estimates for hydroelectric geothermal and other non-fossil electric generating technology (except those defined as cogeneration facilities).

Utility Powerplant Operation and Costs

- Table 13 presents generation costs (i.e., excluding sulfur dioxide and particulate control costs) for different generation technologies. This includes capital costs, fixed O&M costs, and variable O&M costs (in early 1985 dollars). Table 14 presents the combined costs of sulfur dioxide and particulate control equipment at new plants (i.e., scrubbers and ESP equipment).
- Table 15 provides costs for retrofitting existing plants with scrubbers. The costs of upgrading particulate control equipment (i.e., ESPs) when switching to lower sulfur fuels are shown in Table 16.

- Table 17 presents new powerplant heat rates corresponding to powerplants of different types and fuels, and also depending upon capacity utilization. Changes in existing powerplant heat rates over time are also presented.
- Table 18 presents world oil price and natural gas price specifications in early 1985 dollars. These are generally developed separately use ICF's oil and gas market models (or in the case of world oil prices specified by EPA).
- Table 19 presents maximum powerplant availability assumed by plant type; Table 20 indicates the minimum turndown rate specifications for coal and oil/gas steam plants.

Financial Assumptions

- Table 21 presents the assumptions concerning powerplant operating lifetimes, while Table 22 displays such financial parameters as book life, tax depreciation life, input/output dollars, inflation rates, discount rates, and real capital charge rates.

Environmental Regulations

- Table 23 presents existing coal capacity by sulfur dioxide regulatory category. In order to facilitate comparison, (as of 1990) we have aggregated the capacity in this manner. If significant differences are noted between our respective base cases, then I would suggest comparing our SIP limits on a plant by plant basis. Table 24 presents a similar disaggregation for existing oil/gas steam plants. Table 25 lists the various powerplants across the nation for which sulfur dioxide limits are assumed to change between 1985 and 1990.

Coal Reserve Assumptions

- Table 26 presents reserve assumptions as used in the EPA base case by sulfur level.

I believe this represents an extensive list of the assumptions embodied in the EPA base case at the state level and should provide a strong basis for the comparison runs. Once we have received comparable assumptions from the AUSM Model with respect to the NAPAP base case, I suggest we meet again and discuss how best to proceed. We should at that time resolve any problems or questions regarding how our respective assumptions should be used in developing forecasts for the respective models. Prior to that time, I would appreciate receiving AUSM documentation information which is available.

Please call if there are any questions regarding the attached information.

2365C

TABLE 1

ELECTRICITY SALES
(Billion kwh)

	1990	1995	2000	2010
ME	10.3	11.8	13.4	17.2
VT	4.5	5.2	5.9	7.5
NH	7.2	8.2	9.4	12.1
MA	42.2	47.0	52.2	66.8
CT	26.3	29.3	32.5	41.6
RI	6.1	6.8	7.6	9.7
NY	121.3	130.4	140.1	179.4
PA	112.9	122.4	132.5	169.7
NJ	58.3	63.9	69.9	89.5
MD	45.0	51.4	58.7	75.1
DE	7.4	8.4	9.6	12.3
VA	64.2	73.7	84.5	108.2
WV	25.7	29.8	34.6	44.3
NC	79.6	91.0	103.9	132.9
SC	49.4	56.4	64.3	82.4
GA	68.5	81.6	97.1	124.2
FL	121.3	142.4	166.7	213.4
OH	142.8	155.3	168.7	216.0
MI	84.7	94.3	104.8	134.2
IN	72.1	80.2	89.2	114.2
IL	113.2	126.0	140.0	179.3
WI	46.3	51.0	56.1	71.8
KY	48.3	53.2	58.7	75.1
TN	88.0	96.4	105.5	135.1
AL	55.9	61.5	67.7	86.6
MS	28.9	33.1	37.7	48.3
MN	51.2	56.0	61.3	78.5
ND	7.7	8.4	9.2	11.8
SD	6.3	6.9	7.5	9.5
IA	32.3	37.5	43.4	55.6
MO	58.8	67.2	76.7	98.2
KS	26.7	30.5	34.8	44.5
NE	17.6	20.1	22.9	29.4
AR	28.6	32.6	37.2	47.7
OK	46.1	54.1	63.4	81.1
LA	70.9	81.0	92.5	118.4

TABLE 1 (Continued)

ELECTRICITY SALES
(Billion kwh)

	1990	1995	2000	2010
TX	253.4	304.3	365.0	467.2
MT	13.5	15.4	17.6	22.5
WY	9.9	11.6	13.6	17.3
ID	18.2	20.2	22.5	28.8
CO	32.6	38.3	44.8	57.4
NM	11.9	14.7	18.2	23.2
UT	17.1	20.5	24.7	31.6
AZ	38.0	44.6	52.2	66.8
NV	13.8	16.6	20.0	25.6
WA	92.6	103.1	114.6	146.7
OR	44.2	49.1	54.6	69.9
CA	194.6	216.6	240.8	308.2
Total U.S.	2,625.4	2,970.4	3,361.0	4,302.0

TABLE 1(a)

LOAD CURVE ASSUMPTIONS

	Reserve Margin	1990 Load Factor	Average System Capacity Factor
ME	20%	.610	.508
VT	20%	.610	.508
NH	20%	.610	.508
MA	20%	.610	.508
CT	20%	.610	.508
RI	20%	.610	.508
NY	20%	.592	.490
PA	20%	.640	.533
NJ	20%	.540	.450
MD	20%	.560	.467
DE	20%	.560	.467
VA	20%	.605	.504
WV	20%	.655	.546
NC	20%	.590	.492
SC	20%	.590	.492
GA	20%	.575	.479
FL	20%	.600	.500
OH	20%	.658	.548
MI	20%	.630	.525
IN	20%	.615	.513
IL	20%	.540	.450
WI	20%	.650	.542
KY	20%	.560	.467
TN	20%	.655	.546
AL	15%	.565	.491
MS	15%	.570	.496
MN	15%	.610	.530
ND	15%	.600	.522
SD	15%	.600	.522
IA	15%	.530	.461
MO	20%	.520	.433
KS	15%	.495	.430
NE	15%	.495	.430
AR	15%	.550	.478
OK	15%	.520	.452
LA	15%	.650	.565

TABLE 1(a) (Continued)

LOAD CURVE ASSUMPTIONS

	Reserve Margin	1990 Load Factor	Average System Capacity Factor
TX	15%	.588	.511
MT	15%	.650	.565
WY	20%	.700	.583
ID	15%	.630	.548
CO	15%	.630	.548
NM	15%	.680	.591
UT	15%	.660	.574
AZ	15%	.565	.491
NV	15%	.570	.496
WA	15%	.610	.530
OR	15%	.610	.530
CA	15%	.571	.496

TABLE 2

COGENERATION
(Billion kwh)

	1990	1995	2000	2010
ME	1.3	1.6	2.2	2.2
VT	0.4	0.4	0.4	0.4
NH	0.4	0.7	1.0	1.0
MA	0.5	0.7	1.0	1.0
CT	0.6	0.8	1.1	1.1
RI	0.1	0.1	0.1	0.1
NY	1.1	1.4	1.8	1.8
PA	3.2	4.1	5.6	5.6
NJ	1.7	2.4	3.3	3.3
MD	0.4	0.5	0.8	0.8
DE	0.4	0.5	0.5	0.5
VA	0.7	0.9	1.2	1.2
WV	0.4	0.6	0.7	0.7
NC	1.1	1.6	2.3	2.3
SC	0.8	1.0	1.2	1.2
GA	0.9	1.0	1.3	1.3
FL	1.4	1.9	2.5	2.5
OH	1.9	2.4	3.2	3.2
MI	1.8	2.1	2.6	2.6
IN	0.9	1.0	1.2	1.2
IL	2.0	2.6	3.7	3.7
WI	0.6	0.7	0.9	0.9
KY	0.6	0.9	1.3	1.3
TN	0.6	0.6	0.8	0.8
AL	1.3	1.6	2.1	2.1
MS	1.2	1.6	2.1	2.1
MN	0.5	0.6	0.9	0.9
ND	-	-	-	-
SD	-	-	-	-
IA	0.4	0.6	0.8	0.8
MO	0.3	0.4	0.6	0.6
KS	1.0	1.4	2.0	2.0
NE	-	-	-	-
AR	0.7	0.8	1.0	1.0
OK	0.5	0.7	0.9	0.9
LA	6.0	6.8	9.1	9.1

TABLE 2 (Continued)

COGENERATION
(Billion kwh)

	1990	1995	2000	2010
TX	7.6	8.5	11.1	11.1
MT	0.2	0.3	0.5	0.5
WY	0.1	0.1	0.1	0.1
ID	-	-	-	-
CO	0.1	0.1	0.1	0.1
NM	0.1	0.1	0.2	0.2
UT	0.5	0.6	0.7	0.7
AZ	0.3	0.3	0.4	0.4
NV	-	-	-	-
WA	1.1	1.5	2.1	2.1
OR	0.3	0.4	0.5	0.5
CA	6.5	7.6	10.7	10.7
Total U.S.	52.5	64.5	86.6	86.6

TABLE 3

ELECTRICITY IMPORTS FROM CANADA
(Billion kwh on as received basis)

	1990	1995	2000	2010
ME	7.0	8.8	8.8	8.8
VT	7.0	8.7	8.7	8.7
NH	7.0	8.7	8.7	8.7
NY	25.0	25.0	25.0	25.0
MI	-	9.3	9.3	9.3
MN	6.1	6.5	6.1	6.1
IA	-	8.4	16.3	16.3
CA	9.5	10.5	9.5	9.5
Total U.S.	61.6	85.9	92.4	92.4

TABLE 4

TOTAL NUCLEAR CAPACITY
(Gigawatts)

	1990	1995	2000	2010
ME	0.810	0.810	0.810	0.878
VT	0.504	0.504	0.504	0.546
NH	1.150	1.150	1.150	1.247
MA	0.845	0.845	0.845	0.845
CT	3.223	3.223	3.223	3.223
RI	-	-	-	-
NY	5.638	5.638	5.638	5.986
PA	7.676	8.731	8.731	9.638
NJ	3.881	3.881	3.881	4.273
MD	1.650	1.650	1.650	1.650
DE	-	-	-	-
VA	3.290	3.290	3.290	3.290
WV	-	-	-	-
NC	4.840	4.840	4.840	5.338
SC	6.435	6.435	6.435	7.097
GA	3.730	3.730	3.730	4.126
FL	3.638	3.628	3.628	3.768
OH	2.095	2.095	3.300	3.733
MI	3.918	3.918	3.918	4.126
IL	12.732	12.732	12.732	14.093
IN	-	-	-	-
WI	1.560	1.560	1.560	1.560
KY	-	-	-	-
TN	4.650	4.650	4.650	5.486
AL	4.859	7.285	7.285	7.876
MS	1.250	1.250	1.250	1.475
MN	1.539	1.539	1.539	1.539
ND	-	-	-	-
SD	-	-	-	-
IA	0.515	0.515	0.515	0.515
MO	1.150	1.150	1.150	1.357
KS	1.150	1.150	1.150	1.249
NE	1.242	1.242	1.242	1.350
AR	1.748	1.748	1.748	1.748
OK	-	-	-	-
LA	2.038	2.038	2.038	2.404

TABLE 4 (Continued)

TOTAL NUCLEAR CAPACITY
(Gigawatts)

	1990	1995	2000	2010
TX	4.800	4.800	4.800	5.664
MT	-	-	-	-
WY	-	-	-	-
ID	-	-	-	-
CO	0.330	0.330	0.330	0.330
NM	-	-	-	-
UT	-	-	-	-
AZ	3.810	3.810	3.810	4.495
NV	-	-	-	-
WA	1.093	1.093	1.093	1.192
OR	1.080	1.080	1.080	1.178
CA	5.699	5.699	5.699	6.489
Total U.S.	104.558	108.039	109.244	120.002

TABLE 5

NUCLEAR CAPACITY FACTORS

	1990	1995	2000	2010
ME	.683	.713	.713	.713
VT	.683	.713	.713	.713
NH	.683	.713	.713	.713
MA	.664	.694	.695	.695
CT	.664	.694	.695	.695
RI	.664	.694	.695	.695
NY	.640	.670	.670	.670
PA	.625	.657	.657	.657
NJ	.631	.663	.663	.663
MD	.720	.750	.750	.750
DE	.720	.750	.750	.750
VA	.662	.692	.692	.692
WV	-	-	-	-
NC	.625	.658	.658	.658
SC	.625	.658	.658	.658
GA	.640	.670	.670	.670
FL	.671	.701	.701	.701
OH	.606	.640	.651	.651
MI	.647	.680	.680	.680
IL	.640	.670	.670	.670
IN	-	-	-	-
WI	.715	.745	.745	.745
KY	-	-	-	-
TN	.660	.689	.689	.689
AL	.637	.669	.669	.669
MS	.640	.670	.670	.670
MN	.720	.750	.750	.750
ND	-	-	-	-
SD	-	-	-	-
IA	.560	.600	.600	.600
MO	.640	.670	.670	.670
KS	.640	.670	.670	.670
NE	.640	.670	.670	.670
AR	.640	.670	.670	.670
OK	-	-	-	-
LA	.640	.670	.670	.670

TABLE 5 (Continued)

NUCLEAR CAPACITY FACTORS

	1990	1995	2000	2010
TX	.640	.670	.670	.670
MT	-	-	-	-
WY	-	-	-	-
ID	-	-	-	-
CO	.560	.600	.600	.600
NM	-	-	-	-
UT	-	-	-	-
AZ	.600	.635	.635	.635
NV	-	-	-	-
WA	.600	.635	.635	.635
OR	.600	.635	.635	.635
CA	.634	.665	.665	.665
Total U.S.	.640	.670	.670	.670

TABLE 6

EXISTING COAL CAPACITY: 1985
(Gigawatts)

ME	-
VT	0.030
NH	0.501
MA	1.784
CT	-
RI	-
NY	3.258
PA	17.946
NJ	1.648
MD	3.780
DE	0.982
VA	3.903
WV	14.350
NC	12.450
SC	4.412
GA	11.496
FL	6.996
OH	22.812
MI	11.794
IL	16.063
IN	18.064
WI	6.644
KY	14.034
TN	12.546
AL	6.743
MS	2.204
MN	4.779
ND	3.025
SD	0.883
IA	6.136
MO	11.178
KS	5.075
NE	3.022
AR	3.638
OK	4.391
LA	2.690

TABLE 6 (Continued)

EXISTING COAL CAPACITY: 1985
(Gigawatts)

TX	15.300
MT	1.584
WY	5.350
ID	-
CO	4.872
NM	3.830
UT	2.493
AZ	4.411
NV	2.563
WA	1.300
OR	0.530
CA	-
Total U.S.	281.490

TABLE 7

INCREMENTAL NEW COAL CAPACITY: 1986-1990
(Firm Scheduled Capacity)
(Gigawatts)

ME	-
VT	-
NH	-
MA	-
CT	-
RI	-
NY	-
PA	-
NJ	-
MD	-
DE	-
VA	-
WV	-
NC	-
SC	-
GA	0.808
FL	0.965
OH	-
MI	0.676
IL	-
IN	0.515
WI	0.770
KY	0.395
TN	-
AL	0.654
MS	-
MN	-
ND	0.440
SD	-
IA	-
MO	-
KS	-
NE	-
AR	-
OK	0.520
LA	0.640

TABLE 7 (Continued)

INCREMENTAL NEW COAL CAPACITY: 1986-1990
(Firm Scheduled Capacity)
(Gigawatts)

TX	2.394
MT	0.700
WY	-
ID	-
CO	-
NM	0.100
UT	1.860
AZ	0.175
NV	0.125
WA	-
OR	-
CA	-
Total U.S.	11.737

TABLE 8

COAL RECONVERSIONS
(Gigawatts)

	1986-1990	1991-1995
ME	-	0.098
NH	0.093	-
MA	0.909	0.419
CT	0.754	-
RI	-	0.101
NY	0.731	1.863
NJ	-	0.440
VA	0.372	-
FL	0.356	-
AZ	0.259	-
Total U.S.	3.474	2.921

TABLE 9

EXISTING OIL/GAS STEAM CAPACITY: 1985
(Gigawatts)

ME	0.760
VT	-
NH	0.560
MA	4.451
CT	3.416
RI	0.193
NY	14.386
PA	4.293
NJ	3.586
MD/DC	3.395
DE	0.712
VA	2.224
WV	-
NC	-
SC	0.184
GA	0.400
FL	14.769
OH	0.352
MI	3.456
IL	4.378
IN	0.151
WI	0.105
KY	0.063
TN	-
AL	0.047
MS	3.205
MN	0.161
ND	-
SD	0.065
IA	0.127
MO	0.385
KS	2.411
NE	0.410
AR	2.324
OK	6.072
LA	11.504

TABLE 9 (Continued)

EXISTING OIL/GAS STEAM CAPACITY: 1985
(Gigawatts)

TX	37.369
MT	0.070
WY	0.017
ID	-
CO	0.291
NM	1.287
UT	-
AZ	1.694
NV	0.744
WA	-
OR	0.044
CA	21.792
Total U.S.	151.853

TABLE 10

EXISTING TURBINE CAPACITY: 1985

(Gigawatts)

ME	0.078
VT	0.148
NH	0.094
MA	0.661
CT	0.419
RI	0.026
NY	4.629
PA	4.111
NJ	2.707
MD	1.197
DE	0.151
VA	0.522
WV	0.016
NC	0.621
SC	1.356
GA	1.256
FL	5.097
OH	1.543
MI	1.466
IL	1.942
IN	0.490
WI	1.419
KE	0.214
TN	2.036
AL	0.588
MS	0.175
ND	0.238
SD	0.269
MN	1.354
IA	1.504
MO	1.742
KS	1.197
NE	0.660
AR	0.352
OK	0.431
LA	0.232

TABLE 10 (Continued)

EXISTING TURBINE CAPACITY: 1985
(Gigawatts)

TX	1.946
MT	0.023
WY	0.001
ID	0.060
CO	0.634
NM	1.383
UT	0.027
AZ	0.131
NV	1.331
WA	0.315
OR	0.200
CA	1.511
Total U.S.	47.790

TABLE 11

EXISTING COMBINED CYCLE CAPACITY: 1985
(Gigawatts)

ME	0.469
NJ	0.382
PA	0.350
NC	0.080
SC	0.059
FL	0.609
OH	0.225
MI	0.088
IL	0.042
MS	0.026
MN	0.016
IA	0.084
MO	0.085
OK	0.810
LA	0.101
TX	0.626
NM	0.005
AZ	0.895
OR	0.586
CA	1.308
Total U.S.	6.846

TABLE 12

HYDRO AND OTHER CAPACITY[1/]

(Gigawatts)

	1990	1995	2000	2010
ME	0.303	0.303	0.303	0.303
VT	0.168	0.168	0.168	0.168
NH	0.323	0.323	0.323	0.323
MA	1.517	1.517	1.517	1.517
CT	0.121	0.121	0.121	0.121
RI	0.002	0.002	0.002	0.002
NY	6.651	6.728	6.728	6.728
PA	1.764	1.764	1.764	1.764
NJ	0.339	0.339	0.339	0.339
MD	0.496	0.496	0.496	0.496
DE	-	-	-	-
VA	2.731	2.909	2.909	2.909
WV	0.095	0.095	0.095	0.095
NC	1.766	1.766	1.766	1.766
SC	2.166	2.166	2.166	2.166
GA	3.430	3.430	3.430	3.430
FL	0.100	0.200	0.200	0.200
OH	0.192	0.192	0.192	0.192
MI	2.065	2.065	2.065	2.065
IL	-	-	-	-
IN	0.092	0.092	0.092	0.092
WI	0.273	0.273	0.273	0.273
KY	0.716	0.716	0.716	0.716
TN	3.262	3.262	3.262	3.262
AL	2.694	2.694	2.694	2.694
MS	-	-	-	-
MN	0.105	0.105	0.105	0.105
ND	0.423	0.423	0.423	0.423
SD	1.360	1.360	1.360	1.360
IA	0.128	0.128	0.128	0.128
MO	0.951	0.951	0.951	0.951
KS	0.002	0.002	0.002	0.002
NE	0.218	0.218	0.218	0.218
AR	1.067	1.067	1.067	1.067
OK	1.075	1.075	1.075	1.075
LA	-	-	-	-

TABLE 12 (Continued)

HYDRO AND OTHER CAPACITY[1]
(Gigawatts)

	1990	1995	2000	2010
TX	0.525	0.525	0.525	0.525
MT	2.372	2.372	2.372	2.372
WY	0.301	0.301	0.301	0.301
ID	1.528	1.528	1.528	1.528
CO	0.763	0.763	0.763	0.763
NM	0.198	0.498	0.898	1.398
UT	0.492	0.692	1.192	1.792
AZ	2.592	2.592	2.592	2.592
NV	0.725	1.225	1.515	1.915
WA	14.966	15.176	15.380	15.731
OR	6.336	6.426	6.512	6.661
CA	13.120	13.829	14.529	15.929
Total U.S.	80.513	82.877	85.057	88.457

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[1] Includes utility geothermal solar and renewable projects.

TABLE 13

GENERATION COSTS

Capital Costs (early '80 $/kw)

	NE	SE	EC	WC	SC	WE
Bituminous Coal	732	652	681	677	677	689
Subbituminous Coal	774	686	719	715	715	727
Lignite Coal	-	757	-	753	754	767
Oil/Gas Turbine	228	206	209	209	199	202
Nuclear	1370	1250	1370	1320	1250	1420
Combined Cycle	427	386	391	391	373	377
Hydro	1000	1300	1100	1300	1800	2000
Pumped Storage	450	450	450	450	450	450

Fixed O&M Costs (early '80 $/kw-yr)

	NE	SE	EC	WC	SC	WE
Bituminous Coal	6.71	5.15	6.02	6.02	5.97	5.84
Subbituminous Coal	5.81	5.98	5.71	5.71	5.63	6.92
Lignite Coal	-	4.15	-	4.15	3.37	4.15
Oil/Gas Steam	1.51	1.53	1.53	1.53	1.50	1.56
Oil/Gas Turbine	0.39	0.35	0.36	0.36	0.35	0.35
Nuclear	13.95	13.40	14.25	14.25	13.40	14.80
Combined Cycle	5.27	4.73	4.82	4.82	4.64	4.64
Hydro	8.32	8.32	8.32	8.32	8.32	8.32
Pumped Storage	6.88	6.88	6.88	6.88	6.88	6.88

Variable O&M Costs (early '80 mills/kwh)

	NE	SE	EC	WC	SC	WE
Bituminous Coal	1.02	0.81	1.09	1.09	1.09	1.10
Subbituminous Coal	0.90	0.90	0.89	0.89	0.89	1.38
Lignite Coal	-	1.04	-	1.04	1.04	1.60
Oil/Gas Steam	1.62	1.63	1.63	1.63	1.61	1.67
Oil/Gas Turbine	3.13	2.91	2.91	2.91	2.69	2.69
Nuclear	2.45	2.35	2.50	2.50	2.35	2.60
Combined Cycle	1.27	1.18	1.18	1.18	1.09	1.09
Hydro	0.79	0.79	0.79	0.79	0.79	0.79
Pumped Storage	0.65	0.65	0.65	0.65	0.65	0.65

NE: ME, VT, NH, MA, CT, RI, NY, PA, MD, DE, DC, VA, WV
SE: NC, SC, GA, FL, TN, AL, MS
EC: OH, MI, IN, IL, WI, KY
WC: ND, SD, MN, KS, NE, IA, MO
SC: AR, OK, LA, TX
WE: MT, ID, WY, UT, NV, CO, AZ, WA, OR, CA

TABLE 14

POLLUTION CONTROL COSTS FOR NEW UTILITY POWERPLANTS
(Scrubbers and Particulate Control Equipment)

	Sulfur Level						
	Very Low	Low	Low-Medium	Medium	High-Medium	High	Very High
Capital Costs (early '80 $/kw)	131.30	134.41	140.26	200.70	202.38	203.49	212.05
Fixed O&M Costs (early '80 $/kw-yr)	3.56	3.62	3.72	6.78	7.10	7.39	7.64
Variable O&M Costs (early '80 mills/kwh)	1.03	1.17	1.39	1.39	1.52	1.70	1.85
Energy Penalty (%)	2.23	2.07	2.31	4.41	4.60	4.83	4.93
Capacity Penalty (%)	1.56	1.62	1.66	1.94	2.15	2.39	2.53
Reliability Penalty (%)	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Scrubber Type	Dry	Dry	Dry	Wet	Wet	Wet	Wet
Particulate Control	BH	BH	BH	ESP	ESP	ESP	ESP

Sulfur Level	Lbs. $SO2/10^6$ Btu:
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.34-5.00
Very High Sulfur	More than 5.00

TABLE 15

RETROFIT SCRUBBER COSTS FOR EXISTING UTILITY POWERPLANTS - 1.1 FACTOR

	Coal After Preparation lbs. SO2/MMBtu (Long-Term Average)						
	0.80	1.08	1.67	2.50	3.33	5.00	6.67
Scenario Specifications							
A. Annual SO2 Emission Limit (lbs./10^6 Btu)	0.16	0.22	0.34	0.25	0.33	0.50	0.67
B. Annual SO2 Removed (lbs./10^6 Btu)	0.64	0.86	1.32	2.25	3.00	4.50	6.00
C. Percent Removal	80%	80%	80%	90%	90%	90%	90%
D. Scrubber Type	Dry	Dry	Dry	Wet	Wet	Wet	Wet
Scenario Cost (early 1980 $'s)							
A. Capital ($/kw)	134.3	152.6	162.2	161.7	167.6	180.2	186.7
B. O&M							
-- Fixed ($/Kw-yr.)	3.86	3.98	4.09	6.95	7.21	7.75	7.82
-- Variable (mills/Kwh)	1.07	1.23	1.69	1.37	1.48	1.65	1.81
C. Capacity Penalty (%)	1.67	1.67	1.67	1.96	2.06	2.22	2.38
D. Energy Penalty (%)	2.70	2.70	2.70	4.42	4.51	4.68	4.70

Source: EPA estimates. Capital and fixed O&M costs shown above reflect a retrofit factor of 1.1 (i.e., the capital cost of retrofitting a scrubber is 1.1 times the capital cost of installing a scrubber at a new powerplant and the fixed O&M cost is 1.075 times the costs of a new scrubber reflecting a ten percent escalation for three-quarters of the fixed O&M costs). Most existing powerplants have higher costs. Powerplants with no plant-specific estimates were treated as follows:

Size	Capital Cost Relative to a New Scrubber	Fixed O&M Cost Relative to a New Scrubber
Greater than 400 Mw	110%	107.5%
Between 150 and 399 Mw	140%	130.0%
Less than 150 Mw	200%	175.0%

Powerplants retrofitting scrubbers are also assumed to incur a reliability penalty of 2.7 percent.

TABLE 16

PARTICULATE REMOVAL EQUIPMENT UPGRADE COSTS FOR EXISTING UTILITY COAL-FIRED POWERPLANTS GOING TO LOWER-SULFUR COALS
(early 1985 $/kw)

Coal-Type*	0.08	1.08	1.67	2.50	3.33	5.00	6.67
0.80	.	.	.	.	.	.	.
1.08	12	.	.	.	.	.	.
1.67	13	10	.	.	.	.	.
2.50	15	13	10	.	.	.	.
3.33	16	15	13	10	.	.	.
5.00	18	16	15	12	9	.	.
6.67	18	16	15	12	9	4	.

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* lbs. SO2/10^6 Btu cleaned coal.

* * * * * *

Note that for the above assumed particulate upgrade costs.

- Costs are applied to all existing powerplants which shift to lower-sulfur coals.
- Costs are also applied to existing powerplants which retrofit scrubbers and shift coals.

Source: Energy Ventures Analysis estimates developed for EPA.

TABLE 17

HEAT RATES FOR NEW UTILITY POWERPLANTS
(Btu/kwh)

Baseload

	NE	SE	EC	WC	SC	WE
Bituminous Coal	9592	9643	9693	9697	9920	9772
Subbituminous Coal	9863	9915	9967	10049	10200	10049
Lignite Coal	-	10694	-	10694	10644	10644
Oil/Gas Turbine	12500	12500	12500	12500	12500	12500
Nuclear	10700	10700	10700	10700	10700	10700
Combined Cycle	8600	8600	8600	8600	8600	8600

Intermediate

	NE	SE	EC	WC	SC	WE
Bituminous Coal	9922	9975	10028	10031	10262	10109
Subbituminous Coal	10203	10257	10311	10395	10552	10396
Lignite Coal	-	11064	-	11064	10923	10923
Oil/Gas Turbine	10815	10815	10815	10815	10815	10815
Nuclear	10700	10700	10700	10700	10700	10700
Combined Cycle	8800	8800	8800	8800	8800	8800

Seasonal Peak

	NE	SE	EC	WC	SC	WE
Bituminous Coal	10584	10640	10696	10700	10946	10783
Subbituminous Coal	10884	10944	10999	11088	11255	11089
Lignite Coal	-	11802	-	11802	11651	11651
Oil/Gas Turbine	11536	11536	11536	11536	11536	11536
Nuclear	-	-	-	-	-	-
Combined Cycle	10000	10000	10000	10000	10000	10000

Daily Peak

	NE	SE	EC	WC	SC	WE
Bituminous Coal	-	-	-	-	-	-
Subbituminous Coal	-	-	-	-	-	-
Lignite Coal	-	-	-	-	-	-
Oil/Gas Turbine	12360	12360	12360	12360	12360	12360
Nuclear	-	-	-	-	-	-
Combined Cycle	12360	12360	12360	12360	12360	12360

NE: ME, VT, NH, MA, CT, RI, NY, PA, MD, DE, DC, VA, WV
SE: NC, SC, GA, FL, TN, AL, MS
EC: OH, MI, IN, IL, WI, KY
WC: ND, SD, MN, KS, NE, IA, MO
SC: AR, OK, LA, TX
WE: MT, ID, WY, UT, NV, CO, AZ, WA, OR, CA

TABLE 18

WORLD OIL AND NATURAL GAS PRICES
(early '85 $)

	1990	1995	2000	2010
World Oil Price ($/bbl)	29.20	34.10	38.90	49.80
Gas, Region 1 ($/MMBtu)	4.75	5.95	6.75	8.56
Gas, Region 2 ($/MMBtu)	4.55	5.65	6.43	8.21
Gas, Region 3 ($/MMBtu)	4.46	5.57	6.35	8.12
Gas, Region 4 ($/MMBtu)	4.48	5.50	6.27	8.01
Gas, Region 5 ($/MMBtu)	6.06	6.94	7.79	9.74
Gas, Region 6 ($/MMBtu)	4.44	5.53	6.31	8.07
Gas, Region 7 ($/MMBtu)	4.39	5.42	6.19	7.93
Gas, Region 8 ($/MMBtu)	6.42	5.44	6.23	7.96
Gas, Region 9 ($/MMBtu)	4.23	5.26	6.02	7.77
Gas, Region 10 ($/MMBtu)	4.52	5.61	6.39	8.15
Gas, Region 11 ($/MMBtu)	4.36	5.44	6.22	7.99
Gas, Region 12 ($/MMBtu)	4.64	5.79	6.58	8.37

Region 1: ME, UT, NH, MA, CT, RI, NY, PA, NJ
Region 2: MD, DE, DC, VA, WV
Region 3: NC, SC, GA, FL
Region 4: OH, MI, IL, IN, WI, MN
Region 5: E. KY, E. TN
Region 6: W. KY, W. TN, AL, MS
Region 7: ND, SD
Region 8: IA, MO, KS, NE
Region 9: AR, OK, LA, TX
Region 10: MT, WY, ID, CO, UT, AZ, NV
Region 11: NM
Region 12: WA, OR, CA

TABLE 19

MAXIMUM POWERPLANT AVAILABILITY

	Unscrubbed Coal	Scrubbed Coal	Oil/Gas Steam	Oil/Gas Turbine	Hydro
ME	.700	.680	.700	.520	.839
VT	.700	.680	.700	.520	.839
NH	.700	.680	.700	.520	.839
MA	.700	.680	.700	.520	.782
CT	.700	.680	.700	.520	.782
RI	.700	.680	.700	.520	.782
NY	.700	.680	.700	.500	.890
PA	.700	.680	.700	.530	.766
NJ	.700	.680	.700	.500	.882
MD	.700	.680	.700	.500	.723
DE	.700	.680	.700	.500	.723
VA	.700	.680	.700	.510	.702
WV	.700	.680	.700	.550	.702
NC	.700	.680	.700	.500	.655
SC	.700	.680	.700	.500	.655
GA	.700	.680	.700	.500	.820
FL	.700	.680	.700	.550	.970
OH	.720	.700	.720	.530	.726
MI	.720	.700	.720	.550	.726
IL	.700	.680	.700	.500	.726
IN	.700	.680	.700	.530	.726
WI	.720	.700	.720	.550	.720
KY	.700	.680	.700	.500	.873
TN	.720	.700	.720	.530	.723
AL	.700	.680	.700	.500	.741
MS	.700	.680	.700	.530	.770
MN	.700	.680	.700	.550	.860
ND	.750	.730	.750	.550	.906
SD	.750	.730	.750	.550	.906
IA	.700	.680	.700	.500	.700
MO	.700	.680	.700	.500	.832
KS	.700	.680	.700	.500	.940
NE	.700	.680	.700	.500	.940
AR	.700	.680	.700	.500	.650
OK	.700	.680	.700	.500	.650
LA	.750	.730	.750	.550	.650

TABLE 19 (Continued)

MAXIMUM POWERPLANT AVAILABILITY

	Unscrubbed Coal	Scrubbed Coal	Oil/Gas Steam	Oil/Gas Turbine	Hydro
TX	.750	.730	.750	.500	.650
MT	.750	.730	.750	.550	.867
WY	.750	.730	.750	.550	.732
ID	.750	.730	.750	.530	.950
CO	.720	.701	.720	.550	.712
NM	.750	.730	.750	.550	.773
UT	.750	.730	.750	.550	.833
AZ	.700	.682	.700	.500	.833
NV	.700	.682	.700	.500	.833
WA	.720	.700	.720	.550	.872
OR	.720	.700	.720	.550	.872
CA	.700	.680	.700	.500	.850

TABLE 20

MINIMUM TURNDOWN RATES

Coal : 35%

Oil/Gas Steam: 20%

TABLE 21

POWERPLANT LIFETIMES
(Years)

Coal Steam:	60 years
Oil/Gas Steam:	45 years
Nuclear:	35 years
Oil/Gas Turbine:	20 years

TABLE 22

FINANCIAL PARAMETERS

- Book Life (Years)

Coal/Nuclear/Combined Cycle: 30 years
Turbine: 20 years
Pollution Control: 30 years

- Tax Depreciation Life (Years) [1]

Retrofit Pollution Control: 5 years
Others: 15 years

- Year Dollars and Escalation

Input Year Dollars: early 1980
Output Year Dollars: early 1985
Escalation Input to Output Dollars: 1.34
Real Escalation in Capital Costs - 1980-1990: 1.10

- Inflation Rates (% per annum)

1984 : 3.8%
1985 : 4.0%
1986-2010: 5.0%

- Real Discount Rate (% per annum)

Coal Mine: 6.00%
Utility : 4.27%

- Real Capital Charge Rates (% per annum)

Coal/Nuclear/Combined Cycle: 9.0%
Turbine : 10.5%
Pollution Control-New : 9.0%
Pollution Control-Retrofit : 6.5%

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[1] Tax depreciation based on ACRS under ERTA of 1981

TABLE 23

SULFUR DIOXIDE EMISSION LIMITS - EXISTING 1985 COAL CAPACITY
(Gigawatts)

	Scrubbed			Unscrubbed							
	ANSPS	NSPS	SIP	NSPS	Low	Low-Medium	Medium	High-Medium	High	Very High	Total
ME	-	-	-	-	-	-	-	-	-	-	-
VT	-	-	-	-	-	-	-	0.030	-	-	0.030
NH	-	-	-	-	-	-	0.045	0.456	-	-	0.501
MA	-	-	-	-	-	-	1.784	-	-	-	1.784
CT	-	-	-	-	-	-	-	-	-	-	-
RI	-	-	-	-	-	-	-	-	-	-	-
NY	-	0.625	0.100	-	-	-	0.731	1.802	-	-	3.258
PA	-	2.475	1.924	0.657	-	-	1.220	11.670	-	-	17.946
NJ	-	-	-	-	-	0.129	1.232	-	0.287	-	1.648
MD	-	-	-	0.628	-	0.448	0.548	2.156	-	-	3.780
DE	-	-	-	0.400	-	0.242	-	0.340	-	-	0.982
VA	-	-	-	-	0.778	-	3.125	-	-	-	3.903
WV	-	1.252	-	1.300	2.900	2.327	2.561	1.920	2.090	-	14.350
NC	-	-	-	1.440	-	-	11.010	-	-	-	12.450
SC	0.450	0.840	-	-	-	-	1.090	2.032	-	-	4.412
GA	-	-	-	1.636	-	-	-	9.860	-	-	11.496
FL	1.108	0.328	-	1.515	0.200	0.833	0.778	-	0.096	2.138	6.996
OH	-	0.750	-	1.100	0.373	2.509	2.950	-	6.629	8.501	22.812
MI	0.157	-	-	1.721	-	9.784	0.132	-	-	-	11.794
IL	-	1.268	-	1.025	-	6.912	-	1.002	4.644	1.212	16.063
IN	0.344	2.370	0.078	2.304	1.428	-	-	0.872	8.528	2.140	18.064
WI	-	-	-	1.779	-	0.220	-	1.793	2.852	-	6.644
KY	-	2.415	2.672	1.520	1.550	0.308	-	0.354	5.215	-	14.034
TN	-	-	1.064	-	-	0.768	1.595	5.471	3.648	-	12.546
AL	-	0.420	-	0.662	-	1.713	-	3.948	-	-	6.743
MS	-	0.360	-	1.008	-	-	-	-	0.836	-	2.204
MN	-	1.902	0.210	-	-	-	-	2.667	-	-	4.779
ND	-	1.852	-	-	-	-	1.173	-	-	-	3.025
SD	-	0.410	-	-	-	-	0.473	-	-	-	0.883
IA	-	0.150	-	2.871	-	-	-	-	3.115	-	6.136
MO	-	1.100	0.170	0.630	0.555	-	2.030	-	2.569	4.124	11.178
KS	0.280	1.920	1.335	0.858	-	-	0.229	0.453	-	-	5.075
NE	-	-	-	2.030	-	-	0.992	-	-	-	3.022
AR	-	-	-	3.638	-	-	-	-	-	-	3.638
OK	-	-	-	4.391	-	-	-	-	-	-	4.391
LA	0.540	-	-	2.150	-	-	-	-	-	-	2.690
TX	-	5.530	-	7.470	-	-	2.300	-	-	-	15.300
MT	-	1.360	-	-	-	0.224	-	-	-	-	1.584
WY	-	2.339	2.540	-	0.471	-	-	-	-	-	5.350
ID	-	-	-	-	-	-	-	-	-	-	-

TABLE 24

EXISTING OIL/GAS STEAM CAPACITY 1985 (Gigawatts) AND SO2 LIMITS

	Low Sulfur Capacity	Limit (% Sulfur)	High Sulfur Capacity	Limit (% Sulfur)
ME	0.305	0.7	0.455	2.2
VT	-	-	-	-
NH	-	-	0.560	2.2
MA	1.389	0.9	3.062	2.2
CT	3.416	0.9	-	-
RI	0.193	0.9	-	-
NY 1/	7.560	0.4	6.826	2.1
PA	2.653	0.5	1.640	1.5
NJ	3.276	0.3	0.310	1.5
MD/DC	2.613	0.9	0.782	2.0
DE	0.577	0.9	1.039	2.0
VA	1.185	0.8	0.884	2.4
WV	-	-	-	-
NC	-	-	-	-
SC	0.094	2.1	0.090	3.2
GA	0.190	0.6	0.210	1.5
FL	9.142	1.0	5.627	2.5
OH	0.333	1.5	0.019	1.3
MI	1.292	0.7	2.164	1.0
IL	0.770	0.3	3.608	0.8
IN	0.082	0.3	0.069	3.0
WI	0.105	3.0	-	-
KY	0.063	0.7	-	-
TN	-	-	-	-
AL	0.047	1.6	-	-
MS	-	-	3.205	3.0
MN	0.161	1.8	-	-
ND	-	-	-	-
SD	0.065	2.7	-	-
IA	0.127	2.3	-	-
MO	0.385	3.0	-	-
KS	0.064	2.2	2.347	2.7
NE	0.410	2.2	-	-
AR	2.005	1.0	0.319	2.5
OK	4.452	0.7	1.620	1.8
LA	11.504	0.7	-	-

TABLE 24 (Continued)

EXISTING OIL/GAS STEAM CAPACITY 1985 (Gigawatts) AND SO2 LIMITS

	Low Sulfur Capacity	Limit (% Sulfur)	High Sulfur Capacity	Limit (% Sulfur)
TX	37.369	0.6	-	-
MT	0.070	1.8	-	-
WY	0.017	3.0	-	-
ID	-	-	-	-
CO	0.107	0.7	0.184	1.4
NM	1.287	0.3	-	-
UT	-	-	-	-
AZ	1.694	0.9	-	-
NV	0.744	0.7	-	-
WA	-	-	-	-
OR	0.044	1.8	-	-
CA [1]	17.798	0.3	3.994	0.5
Total U.S.	113.588		38.265	

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[1] Downstate New York and Southern California were chosen to represent their respective statewide SO2 limits because the oil/gas steam generating capacity in these areas dominated capacity in other areas of the two states.

TABLE 25

CHANGES IN SO2 LIMITS: 1985-1990

		1985	1990
NY:	Jamestown Board Carlson #2-#6	3.80	3.40
	New York State Elec. Goudey #7, #8	3.80	3.40
	New York State Elec. Greenidge #1-#4	3.80	3.40
	New York State Elec. Hickling #1, #2	3.80	3.40
	New York State Elec. Jennison #1, #2	3.80	3.40
	New York State Elec. Milliken #1, #2	3.80	3.40
	Niagara Mohawk Power Dunkirk #1-#4	3.80	3.40
	Rochester Gas & Elec. Station #7, #1-#4	3.80	3.40
	Rochester Gas & Elec. Station #3, #12	3.80	3.40
PA:	GPU Homer City #3	1.70	1.20
	GPU Homer City #1, #2, #5	2.80	3.70
	GPU Seward #4, #5	2.80	3.70
OH:	AEP Muskingum River #1-#5	6.48	7.60
MI:	Consumers Power Campbell #1, #2	2.50	1.66
WI:	Dairyland Power Stoneman #1, #2	NL	4.00
	Dairyland Power Alma #1-#5	6.67	4.00
	Dairyland Power Genoa #6	6.67	4.00
	Lake Superior Bayfront #5, #6	6.67	4.00
	Madison Gas & Elec. Blount St. #3, #5-#7	NL	5.80
	Manitowoc Public Manitowoc #3-#6	NL	4.00
	Marshfield Electric Wildwood #4, #5	NL	4.00
	Menasha Electric Menasha #1-#4	NL	4.00
	Wisconsin Elec. Eastwells #1	NL	5.50
	Wisconsin Elec. Port Washington #2-#5	NL	4.00
	Wisconsin Elec. Valley #1, #2	NL	3.28
	Wisconsin Elec. North Oak Creek #1-#4	NL	4.00
	Wisconsin Elec. South Oak Creek #5-#8	NL	4.00
	Wisconsin Power Black Hawk #3, #4	NL	4.00
	Wisconsin Power Columbia #1	NL	4.00
	Wisconsin Power Dewey, Nelson #1, #2	6.67	4.00
	Wisconsin Power Edgewater #3, #4	NL	4.90
	Wisconsin Power Rock River #1, #2	NL	4.00
	Wisconsin Public Pulliam #3-#8	5.58	4.50
	Wisconsin Public Weston #1, #2	5.00	4.00

NL: No Limit

TABLE 26

ICF RESERVE ASSUMPTIONS BY SULFUR LEVEL [a]

(Millions of Tons In-place)

	Sulfur Level [b]						
Region	Low	Low-Medium	Medium	High-Medium	High	Very High	Total
Northern Appalachia	920	2,895	11,870	27,298	20,819	20,187	83,989
Central Appalachia	18,589	21,732	7,931	1,298	1,251	-	50,801
Southern Appalachia	1,150	1,375	1,045	1,175	800	-	5,545
Midwest	-	1,940	2,840	3,720	51,031	154,711	214,242
Central West	86	305	491	221	1,732	13,567	16,402
Gulf	-	-	5,500	10,100	5,000	-	20,600
Eastern Northern Great Plains	3,999	11,201	21,000	3,000	-	-	39,200
Western Northern Great Plains	76,274	55,101	60,102	-	-	309	191,786
Rockies	35,012	15,751	8,414	-	438	237	59,852
Southwest	3,950	7,100	4,650	-	-	-	15,700
Washington	-	-	1,431	-	-	-	1,431
Alaska	5,000	-	-	-	-	-	5,000

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[a] These are estimates of in-place reserves not estimates of what may be economic at any point in time.

[b]

	Sulfur Level:		Lbs. S02/10^6 Btu	Approximate Percent Suflur (24 Million Btu/Ton)
B	Low Sulfur	:	Less than 1.09 lbs.	Less than 0.65%
D	Low-Medium Sulfur	:	1.09-1.67 lbs.	0.65-1.00%
E	Medium Sulfur	:	1.68-2.50 lbs.	1.01-1.50%
F	High-Medium Suflur	:	2.51-3.33 lbs.	1.51-2.00%
G	High Sulfur	:	3.34-5.00 lbs.	2.01-3.00%
H	Very-High Sulfur	:	Greater than 5.00 lbs.	Greater than 3.00%

TABLE 23 (Continued)

SULFUR DIOXIDE EMISSION LIMITS - EXISTING 1985 COAL CAPACITY
(Gigawatts)

	Scrubbed			Unscrubbed							
	ANSPS	NSPS	SIP	NSPS	Low	Low-Medium	Medium	High-Medium	High	Very High	Total
CO	0.650	0.815	-	1.016	2.379	0.012	-	-	-	-	4.872
NM	0.105	1.250	2.475	-	-	-	-	-	-	-	3.830
UT	-	1.615	-	-	-	0.878	-	-	-	-	2.493
AZ	-	1.810	0.116	0.235	2.250	-	-	-	-	-	4.411
NV	0.375	0.110	0.220	0.250	1.608	-	-	-	-	-	2.563
WA	-	-	-	-	-	-	1.300	-	-	-	1.300
OR	-	-	-	-	0.530	-	-	-	-	-	0.530
CA	-	-	-	-	-	-	-	-	-	-	-
Total U.S.	4.009	35.266	12.904	44.234	15.022	27.307	37.298	46.826	40.509	18.115	281.490

Low : Less than 1.09 lbs. SO2/106 Btu
Low-Medium : 1.09-1.66 lbs. SO2/106 Btu
Medium : 1.67-2.50 lbs. SO2/106 Btu
High-Medium : 2.51-3.34 lbs. SO2/106 Btu
High : 3.35-5.00 lbs. SO2/106 Btu
Very High : More than 5.00 lbs. SO2/106 Btu

Note: the sulfur categories for unscrubbed plants reflect the coals that can be burned to meet their emission limits.

APPENDIX D CEUM SO_2 EMISSIONS ADJUSTED TO AUSM GENERATION LEVELS

The approach here is to take data from the tables in section 5 and recalculate CEUM model emissions on the basis of AUSM generation levels for fossil fuel units. The following information is taken from these tables:

Table	Parameter	Year	Value	Units
5.10	AUSM Coal Generation	1990	1.32	PWh
5.10	CEUM Coal Generation	1990	1.50	PWh
	Difference (D_1)	1990	0.18	PWh
5.10	AUSM Oil/Gas Generation	1990	0.44	PWh
5.10	CEUM Oil/Gas Generation	1990	0.22	PWh
	Difference (D_2)	1990	0.22	PWh
5.10	AUSM Coal Generation	1995	1.52	PWh
5.10	CEUM Coal Generation	1995	1.58	PWh
	Difference (D_3)	1995	0.06	PWh
5.10	AUSM Oil/Gas Generation	1995	0.44	PWh
5.10	CEUM Oil/Gas Generation	1995	0.38	PWh
	Difference (D_4)	1995	0.06	PWh
5.12	CEUM Coal Consumption	1990	15.80	10^{15} Btu
5.12	CEUM Oil/Gas Consumption	1990	2.51	10^{15} Btu
5.12	CEUM Coal Consumption	1995	16.79	10^{15} Btu
5.12	CEUM Oil/Gas Consumption	1995	4.22	10^{15} Btu
5.14	Reported AUSM Emissions	1990	16.63	10^6 tons
5.14	Reported CEUM Emission	1990	17.79	10^6 tons
5.14	Reported AUSM Emissions	1995	17.28	10^6 tons
5.14	Reported CEUM Emissions	1995	18.60	10^6 tons
5.15	CEUM Coal Emission Rate	1990	2.14	lb/MMBtu
5.15	CEUM Oil/Gas Emission Rate	1990	0.79	lb/MMBtu
5.15	CEUM Coal Emission Rate	1995	2.08	lb/MMBtu
5.15	CEUM Oil/Gas Emission Rate	1995	0.58	lb/MMBtu

These values are used to adjust the CEUM emissions by the amount of difference in generation between CEUM and AUSM using the following relationship:

$$E_A = E_R - \{[(D_C F_C R_C)/CG_C] + [(D_G F_G R_G)/CG_G]\} \quad \text{where,}$$

E_A = Adjusted Emissions
E_R = Reported Emissions
D_C = Difference in Coal Generation
D_G = Difference in Gas/Oil Generation
(Note: the sign of D is negative when AUSM > CEUM)
F_C = Coal Fuel Consumption
F_G = Gas/Oil Fuel Consumption
R_C = Rate of Emissions Release (Coal)
R_G = Rate of Emissions Release (Gas/Oil)
C = Units Conversion Constant (value = 2)
G_C = Generation (Coal), and
G_G = Generation (Gas/Oil)

Calculation for 1990

$$E_A = 17.79 - \{[(0.18)(15.80)(2.14)/(2)(1.50)] +$$

$$[(-0.22)(2.51)(0.79)/(2)(0.22)]\}$$

E_A (CEUM) = 16.75
E_B (AUSM) = 16.63

Calculations for 1995

$$E_A = 18.60 - \{[(0.06)(16.79)(2.08)/(2)(1.58)] +$$

$$[(-0.06)(4.22)(0.58)/(2)(0.38)]\}$$

E_A (CEUM) = 18.13
E_B (AUSM) = 17.28

These calculations illustrate that almost all of the differences in SO_2 emissions outputs of these models can be explained by coal versus gas/oil generation differences in 1990 and about 35 percent of the difference explained by fossil generation differences in 1995.